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HYDROCARBON PROCESSING®

RENEWABLE DIESEL FACILITIES

TECHNOLOGIES DRIVING DECARBONIZATION
of the oil and gas industry

Gulf Energy

HYDROCARBON PROCESSING®

APRIL 2021 | Volume 100 Number 4
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SPECIAL FOCUS: CLEAN FUELS

ENGINEERING AND CONSTRUCTION

PROCESS ENGINEERING

PROCESS OPTIMIZATION

PROCESS CONTROL, INSTRUMENTATION AND AUTOMATION

WATER MANAGEMENT

MAINTENANCE AND RELIABILITY

ENVIRONMENT AND SAFETY

DEPARTMENTS

COLUMNS

WEB EXCLUSIVE

Cover Image: Gazprom Neft is investing in the two-stage Omsk oil refinery modernization project. The capital-intensive investment will enable the refinery to increase conversion rate and produce Euro-5 fuels. Photo courtesy of Gazprom Neft.

99TH ANNIVERSARY |1922–2021|

HP Industry Perspectives

Two events to honor the industry's people and technologies

In the second half of 2021, *Hydrocarbon Processing* is hosting two events to showcase the leading technologies and people in the refining, petrochemicals and gas processing/LNG industries: The International Refining and Petrochemical Conference (IRPC) and the *HP* Awards. A "call for abstracts" has opened for both events.

HYDROCARBON PROCESSING® IRPC OPERATIONS

IRPC Operations. Built on the essence of topics in the pages of *Hydrocarbon Processing*, IRPC Operations will highlight the latest equipment, services, tools and technologies to optimize refining and petrochemical operations and maintenance efforts for a safer, more efficient, more profitable and sustainable work environment.

The global, virtual event, to be held September 21–22, will focus on several categories that address the challenges in hydrocarbon processing operations. These categories include emerging processing technologies; catalysts technologies; engineering/construction best practices; integration techniques; maintenance and reliability; digital transformation; circular economy; process controls, instrumentation and automation; clean fuels, biofuels and alternative fuels production; sustainability and more.

The IRPC Operations "call for abstracts" is underway. To submit an abstract, visit www.HydrocarbonProcessing.com/events.

HYDROCARBON PROCESSING® 2021 AWARDS

***HP* Awards.** Over the past several years, *Hydrocarbon Processing* has honored the latest technologies and people that advance the industry in numerous ways. The 2021 *HP* Awards will be held on October 28 and will honor the downstream energy sector's leading technology innovations, as well as outstanding personal contributions to the industry.

The awards ceremony will recognize leading technologies in the areas of process optimization, automation, catalysts, digitalization, safety, flow control, instrumentation, engineering, sustainability and much more. The event will again feature special People/Company categories such as EPC of the year, licensor of the year, executive of the year, most promising engineer and lifetime achievement.

The abstract submission period is open. To submit an abstract and/or to find more information on the event and sponsorships, visit www.HydrocarbonProcessing/events. HP

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Because *Hydrocarbon Processing* is edited specifically to be of greatest value to people working in this specialized business, subscriptions are restricted to those engaged in the hydrocarbon processing industry, or service and supply company personnel connected thereto.

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HP Editorial Comment

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Clean fuels: Maximizing production without forsaking profitability

Over the past several decades, the hydrocarbon processing industry has invested heavily in new processing units to produce low-sulfur and ultra-low-sulfur (ULS) transportation fuels. This increase in "clean fuels" production focuses on mitigating pollutants from vehicle exhaust.

In the past 30 yr, the global refining industry has invested hundreds of billions of dollars to reduce the amount of sulfur in gasoline, jet fuel, diesel, etc. At present, millions of tons per year of additional secondary unit capacity is under development.

According to OPEC's *World Oil Outlook 2020,* secondary unit capacity (conversion, desulfurization and octane) is forecast to increase approximately 10 MMbpd by 2026. More than half of this total will be for new desulfurization capacity (**FIG. 1**). Most new desulfurization capacity will be built in Asia and the Middle East, which account for nearly 4 MMbpd of new desulfurization capacity within the forecast period.

The stark increase in new desulfurization capacity is due to new stringent clean fuels regulations being adopted by nations around the world.

Renewables and biofuels. Organizations around the world are also investing in increasing biofuels blending and in new production capacity for alternative fuels and renewable fuels. These are emerging trends in several regions/countries.

For example, many countries are mandating the increase in biofuels blending with conventional fuels. These programs not only provide a method of reducing emissions, but also enable many countries to mitigate costly crude oil imports.

Finally, a major trend in new clean-fuels production is the increase in new renewable fuels plants being built. For example, several retrofit projects and new renewable diesel plants are being built in the U.S. to increase the production of renewable diesel.

Analysis and discussion. Due to the stark increase in new government regulations to curb emissions, this issue is dedicated to showcasing several technologies that will help advance the production of renewable diesel, helping the marine industry comply with strict marine fuels regulations, adhering to new ULS fuels production initiatives and using digital technologies to create smart renewable facilities. These technologies are a glimpse at the many processes available to maximize the production of clean fuels and optimize operations without forsaking profitability. HP

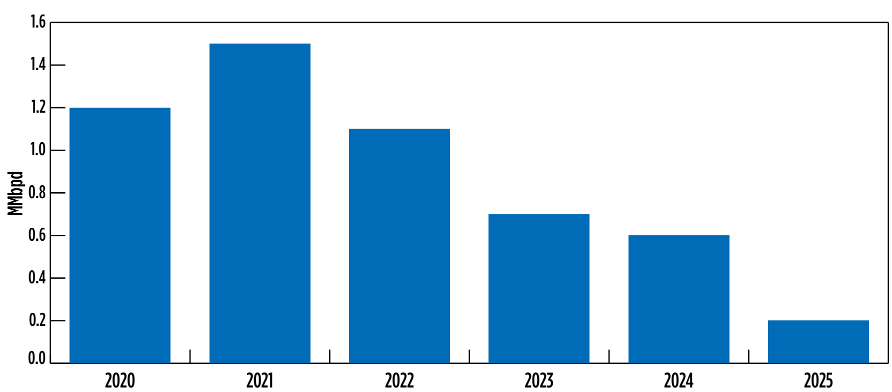

FIG. 1. Global desulfurization capacity growth, 2020–2025 (MMbpd). Source: OPEC.

INSIDE THIS ISSUE

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HP Construction

AFRICA

Sprea Misr has awarded **Nuberg EPC** an engineering, procurement and construction (EPC) contract for a 500-tpd sulfuric acid plant in Ramadan City, Egypt. The plant will also incorporate a 5-MW turbine with a steam-based power generation plant. The sulfuric acid produced will be used to produce ammonia and urea for the agriculture industry.

ASIA-PACIFIC

Numaligarh Refinery Ltd. (NRL) has selected **Axens** to supply advanced technologies for the Numaligarh Refinery Expansion project. Located in Golaghat, Assam, India, NRL is expanding the refinery by 6 MMtpy to 9 MMtpy. The expansion will enable NRL to produce fuels that adhere to India's strict Bharat Stage-6 (BS-6) fuel standard. Axens will license technologies for the naphtha hydrotreating unit, continuous catalytic reforming unit, C_5–C_6 isomerization unit and the fluid catalytic cracking (FCC) gasoline selective desulfurization unit.

NRL also awarded **Lummus Technology** a contract to supply its Indmax FCC technology for the refinery. According to Lummus, the Indmax FCC unit will process 1.96 MMtpy of mixed hydrotreated VGO feed with the flexibility to operate in gasoline mode, as well as in maximum propylene production mode. This contract is in addition to an earlier announced technology licensing award by NRL to **Chevron Lummus Global,** a JV between **Chevron** and Lummus. Chevron Lummus Global will provide its LC-FINING technology for the refinery.

Refining NZ has made significant progress in a study to convert the Marsden Point refinery in New Zealand to an import terminal. Due to increased competition from modern Asian refineries, coupled with a collapse in refined product demand from COVID-19, Refining NZ plans to invest approximately $145 MM to convert the refinery into an import terminal.

Honeywell UOP will provide several licensed technologies to **Shandong Yulong Petrochemical Co. Ltd.'s** integrated petrochemicals complex in Longkou, Shandong Province, China. These platforming and aromatics technologies will enable Shandong Yulong to produce 3 MMtpy of mixed aromatics.

Indian Oil Corp.'s (IOC's) subsidiary, **Chennai Petroleum Corp. Ltd.,** has received approval to build a 9-MMtpy refinery in Nagapattinam, Tamil Nadu, India. The $4-B refinery, which will take approximately 4 yr to build from final investment approval, will produce gasoline and diesel that adhere to India's BS-6 fuel standard.

Toyo Engineering Corp. and **Velocys** have signed a collaboration agreement to produce sustainable jet fuel and other renewable fuels in Japan. The agreement follows the successful launch of the JV's biomass-to-jet fuel demonstration plant in Japan. The latest agreement is in hopes of launching a commercial-scale biomass-to-jet fuel plant in the country.

IOC has started construction on a new $132.7-MM catalytic dewaxing unit at its Haldia refinery in Haldia, India. The unit, which will use **Chevron Lummus Global's** ISODEWAXING and ISOFINISHING technologies, will increase the refinery's ability to produce lubricant base oils. The project is scheduled to be completed in late 2022.

In late January, **LyondellBasell** and **Sinopec** finalized a JV to produce propylene oxide (PO) and styrene monomer (SM). The JV, which will operate under the name **Ningbo ZRCC LyondellBasell New Material Co. Ltd.,** will build a 275,000-tpy PO plant and a 600,000-tpy SM plant in Zhenhai Ningbo, China. The products produced will be used for the domestic market.

EUROPE

Sibur announced in mid-February that the $10-B Amur Gas Chemical complex will be operational by mid-2024, six months ahead of schedule. The complex will produce 2.3 MMtpy of polyethylene (PE) and 400,000 tpy of polypropylene (PP).

ORLEN awarded **DuPont Clean Technologies** a licensing, engineering and technical services contract for an alkylation and spent acid regeneration units at the Mažeikiai refinery in Mažeikiai, Lithuania. The two units will increase the refinery's complexity and flexibility. Both units are expected to startup in 2025.

OMV is expanding and modernizing its cracker and petrochemical units at the Burghausen refinery in Germany. The projects, which are scheduled to be completed in 3Q 2022, will help OMV increase ethylene and propylene production by 50,000 tpy.

KazMunayGas awarded a front-end engineering and design (FEED) contract to **JGC** for a planned gas separation plant. The 957-MMft^{3}d facility will be built in Kazakhstan and provide ethane feedstock to **Kazakhstan Petrochemical Industries Inc.'s (KPII's)** Atyrau gas chemical complex. The Atyrau complex will use the ethane as a feedstock for a planned 1.25-MMtpy PE plant. At present, KPII is building a $2.6-B, 500,000-tpy PP plant at the site, which will be completed by the end of this year. The site's second phase includes the construction of the PE unit.

In late January, Russia's Sberbank approved more than $3.6 B in additional financing for **Novatek's** Arctic LNG 2 project. The $21-B, 20-MMtpy project is scheduled to begin operations in 2023 and reach full operations in 2026.

Tecnimont SpA and **KT-Kinetics Technology SpA,** subsidiaries of **Maire Tecnimont,** were awarded two EPC contracts for **SOCAR's** Heydar Aliyev refinery modernization project in Azerbaijan. According to Maire Tecnimont's press

release, the scope of the first contract includes the installation of an FCC gasoline hydrotreating unit, while the other pertains to the installation of an LPG mercaptan oxidation unit and an amine treatment and LPG pretreatment unit. These projects will enable the refinery to produce Euro-5 gasoline.

In early February, **Lukoil** commissioned a \$135-MM deasphalting plant at its Volgograd refinery in Russia. The new plant will enable the refinery to produce high-quality basestocks and is part of a wider \$2.33-B program to modernize the refinery.

Lukoil also plans to commission an isomerization unit and delayed coking unit at its 17-MMtpy Kstovo refinery in the Nizhny Novgorod region by 2022.

Jizzakh Petroleum let a technology licensing contract to **Versalis,** the chemical subsidiary of **Eni,** for a \$2.8-B grassroots methanol-to-olefins (MTO) gas-to-chemicals complex. Versalis will provide licensing technology for a low-density PE (LDPE) plant-ethylene vinyl acetate (EVA) swing unit at the facility being built in the Bukhara region of southwestern Uzbekistan. The MTO gas-to-chemicals complex will process 1.5 Bm^{3}y of domestically-sourced natural gas into 500,000 tpy of high-quality polymers, including LDPE, EVA, polyethylene terephthalate and PP. Once completed, the complex will help Uzbekistan monetize domestic natural gas resources and mitigate costly imports.

LATIN AMERICA

NextChem, a subsidiary of **Maire Tecnimont,** and **Essential Energy USA Corp.** have engaged in a FEED contract and Memorandum of Understanding for a renewable diesel plant in South America. The 200,000-tpy facility will convert natural oil, waste vegetables oils and tallow into high-quality renewable diesel. NextChem will be the exclusive EPC contractor on the project, which is scheduled to be completed in 2023.

MIDDLE EAST

Qatar Petroleum has awarded a contract for the first phase of its nearly \$29-B North Field expansion project. The contract, awarded to **Chiyoda** and **Technip,** will enable Qatar to increase LNG production from 77 MMtpy to 110 MMtpy by 2026. The project's second phase will allow Qatar to increase LNG production capacity to 126 MMtpy by 2027.

U.S.

PTT Global Chemical America announced it is seeking a partner for its \$10-B ethane cracker project in Ohio. The company plans on making a final investment decision (FID) in 2021 on the capital-intensive project. If built, the project will produce 1.5 MMtpy of ethylene. Operations are scheduled to begin 4 yr–6 yr after an FID is taken.

CVR Energy is moving into the next phase of its alkylation project at its refinery in Wynnewood, Oklahoma. CVR Energy awarded **KBR** a contract to revamp the refinery's existing hydrofluoric acid alkylation unit. KBR will provide detailed engineering of the process equipment, proprietary equipment supplies and module fabrication. The project's completion date is scheduled for late 2024.

Shintech plans to increase polyvinyl chloride (PVC) and vinyl chloride monomer (VCM) production capacity with the construction of a grassroots, integrated plant in Plaquemine, Louisiana. The \$1.25-B plant will produce 390,000 tpy of PVC and 380,000 tpy of VCM. The plant is scheduled to begin operations by 2024.

Diamond Green Diesel, a JV between **Darling** and **Valero,** has received approval from both companies' boards of directors to build a new renewable diesel facility. The \$1.45-B plant will be located at Valero's Port Arthur, Texas refinery. Once completed in 2H 2023, the plant will produce 470 MMgpy of renewable diesel.

Venture Global announced plans to build a second LNG export terminal adjacent to its Calcasieu Pass LNG terminal now under construction. The 20-MMtpy CP2 LNG plant will consist of 18 liquefaction trains and be built in two phases. Phase 1 will include the construction of nine liquefaction trains, as well as the construction of feedstock pipelines and compressor stations. Phase 1 construction activities—subject to regulatory approvals—are scheduled to begin in 2Q 2023, with operations to begin in 2Q 2025. Full completion of Phase 1 activities is scheduled for mid-2026. HP

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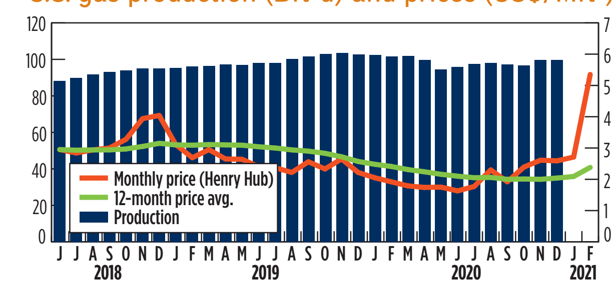
HP Industry Metrics

U.S. refinery margins extended their upward trend and showed the largest gains relative to the other regions due to a rise in refinery outages as extreme cold temperatures caused partial and complete refinery shutdowns. Refinery margins in Europe lost ground with negative performance registered in the naphtha, jet/kero and high-sulfur fuel oil segments. Asian product markets strengthened slightly, reinforced by product supply disruptions caused by unexpected refinery outages within and outside the region. HP

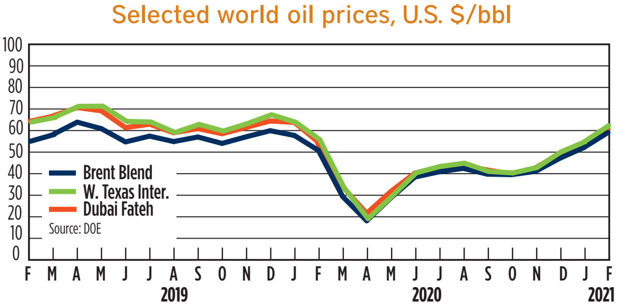
An expanded version of Industry Metrics can be found online at HydrocarbonProcessing.com.

U.S. gas production (Bft^3d) and prices (US$/$Mft^3$)

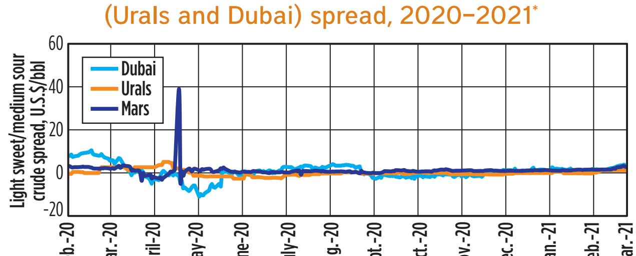


Production equals U.S. marketed production, wet gas. Source: EIA.

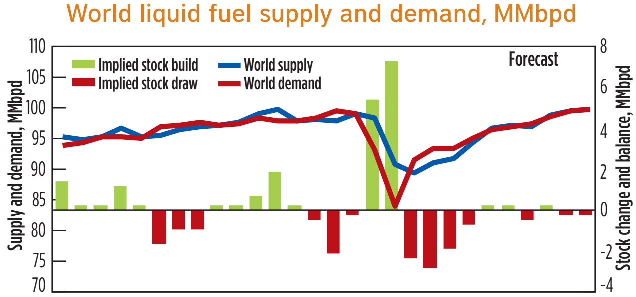
Selected world oil prices, U.S. $/bbl



Brent dated vs. sour grades (Urals and Dubai) spread, 2020–2021*

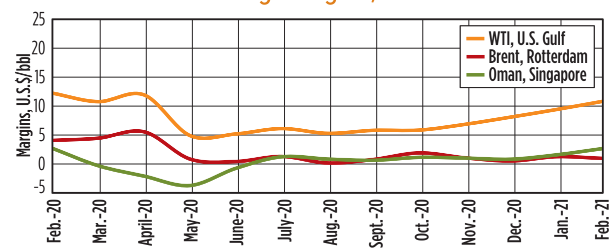


World liquid fuel supply and demand, MMbpd

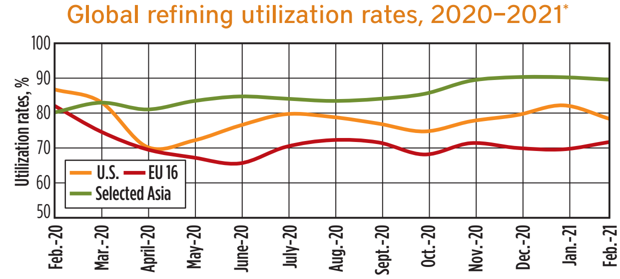


Source: *EIA Short-Term Energy Outlook*, March 2021

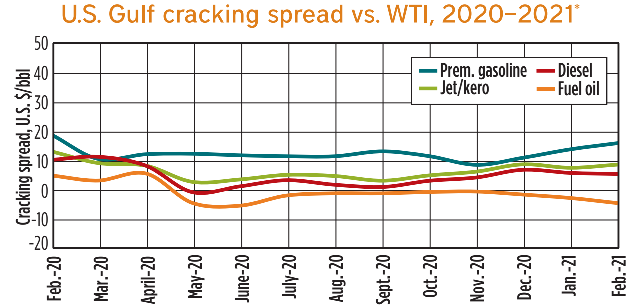
Global refining margins, 2020–2021*



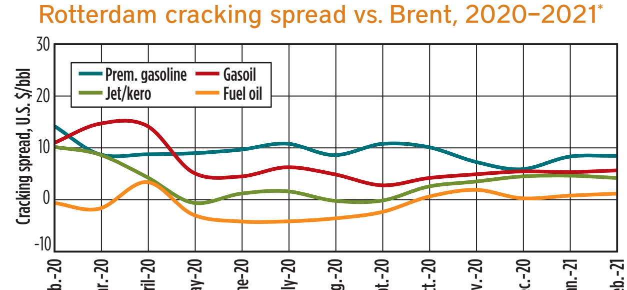
Global refining utilization rates, 2020–2021*



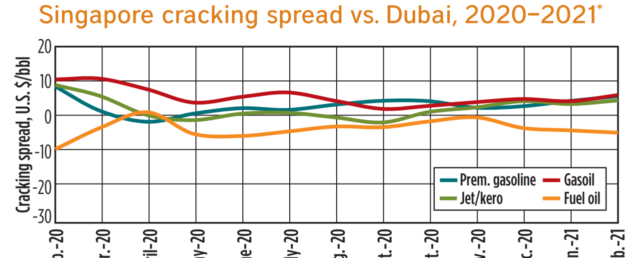
U.S. Gulf cracking spread vs. WTI, 2020–2021*



Rotterdam cracking spread vs. Brent, 2020–2021*



Singapore cracking spread vs. Dubai, 2020–2021*



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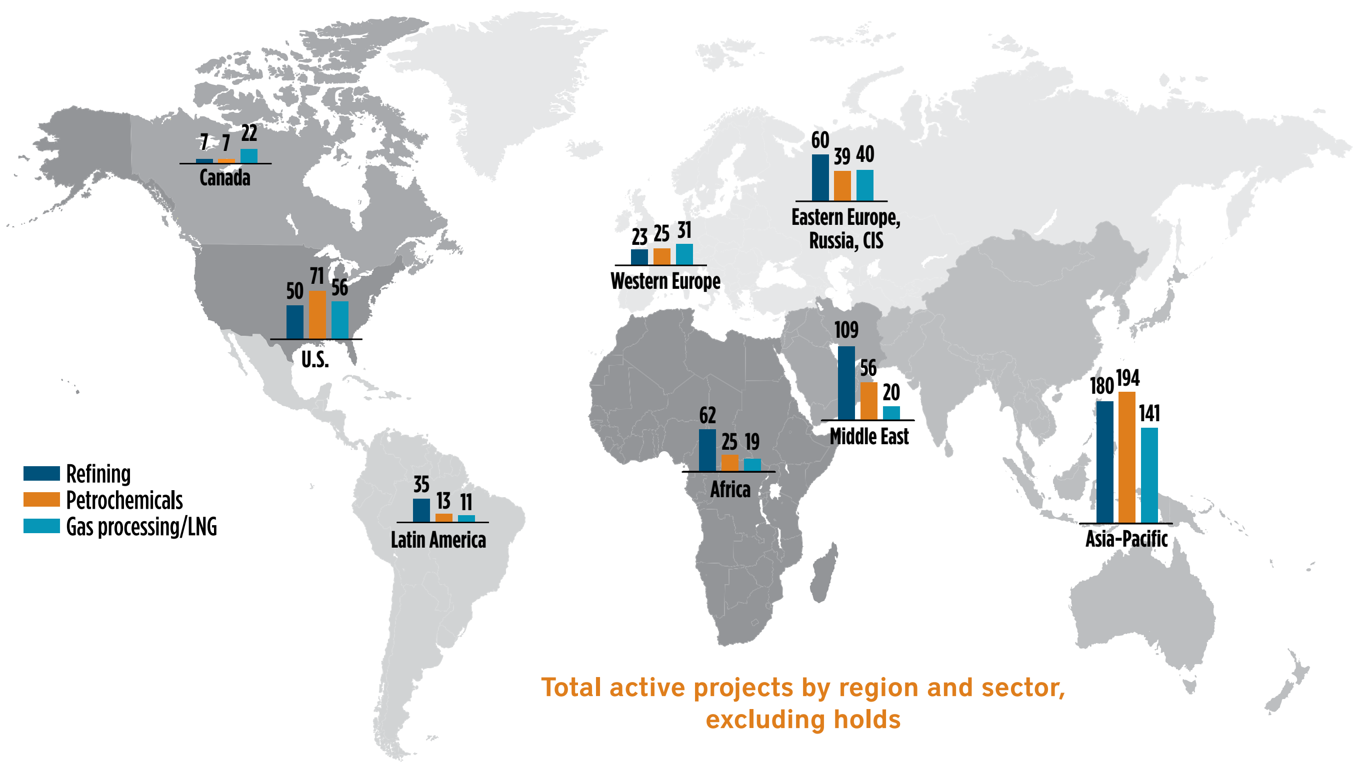
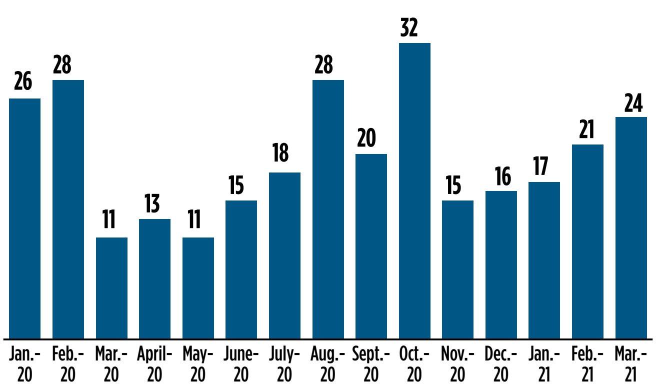
HP Global Project Data

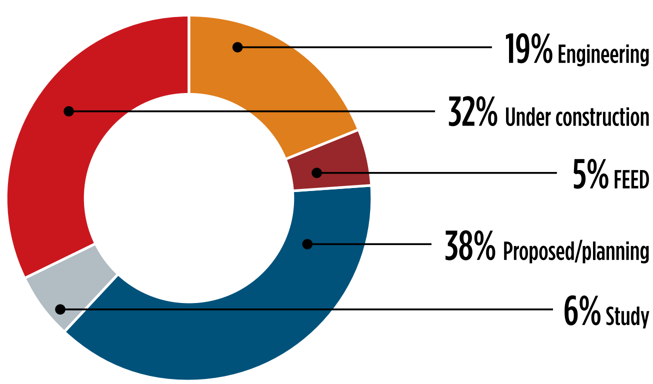
According to Gulf Energy Information's Global Energy Infrastructure database, new capital project investments have increased each month since November 2020. Over the past month, the Boxscore Database recorded a yearly high 24 new capital project announcements in the global hydrocarbon processing industry. Approximately half of these projects are in the Asia-Pacific region, primarily in India. When compared to 1Q 2020, new project announcements through the first quarter of this year are about the same—65 in 1Q 2020 vs. 62 in 1Q 2021. In total, the Boxscore Database is tracking nearly 1,300 projects around the world. HP



Total active projects by region and sector, excluding holds



New project announcements, January 2020–March 2021



Active project market share by activity level

Taking ownership of problems

FIG. 1. The Brazos Wind Farm (also known as the Green Mountain Energy Wind Farm) near Fluvanna, Texas contains 160 wind turbines, each with a generating capacity of 1 MW.

Taking ownership of issues during a critical or troubling time is just as important as assuming responsibility during times of opportunity and benefit. In fact, one could argue that accountability is even more important than opportunism, since there can be much more to lose when the threats of breakdown, failure and harm to personnel, plant and/or enterprise loom near.

Here, we highlight two recent, relevant examples related to the ownership of problems: one in which ownership was present, and one in which it was not. These examples serve as resounding reminders of how service excellence and responsibility—or, conversely, failure and finger-pointing—at the upper levels of organizations can have a strong hand in shaping the perception of how crises are handled.

Turbomachinery setback averted. A few years ago, large-scale petrochemical producer "ABC" ran into performance problems with one of its major steam turbines. The steam turbine's vendor-manufacturer, "DEF," was called in amid assurances that DEF had delivered a machine that met ABC's specifications and had passed both a mechanical run test and subsequent performance tests. DEF concluded that ABC must have done something that damaged the machine, but DEF would participate in finding out what, exactly, ABC had done to damage an excellent product.

Later that same year—and halfway around the globe—one of ABC's affiliates was engaged in starting up a new plant. The large turbomachines at that affiliate had been purchased from vendor-manufacturer "GHJ"; however, a speed instability problem was detected during onsite test runs very close to the time of full-scale commissioning. GHJ immediately sent its national sales manager ("NSM") and three of its highly competent engineers. One of ABC's principal startup advisors remembers the first meeting called by NSM, and committed NSM's words to his notebook: "I am very sorry for any problems that this steam turbine or any other machine from ["GHJ"] has caused to an ["ABC"] project, and I am here to ascertain that ["GHJ"] will do everything to correct our problem so that your company will not experience any startup delays."

By taking ownership of issues that arise, GHJ has earned the trust of many end-user companies. The company's machines are clearly among the world's best, but the way that GHJ handles the few, infrequent problems it encounters sets it apart from its competition. Competence and truthfulness will carry the day, and will ultimately be rewarded in full. Moreover, these two attributes are indispensable to adequately planning for the future.

The future of the Texas power grid. Proper planning for the future requires drawing the right conclusions from an unbiased examination of the past. Unbiased examinations have no hidden agenda. Regrettably, we have time and space for only one example.

For this scenario, let us say that Texas had experienced a brutal winter. Suppose our examination of the past winter had found that many wind turbine blades in Texas had failed due to ice encrustation; however, blades in Canada had survived many more severe Canadian winters. In that case, blades in Texas must lack something that Canadian blades have.

Furthermore, if 10% of all the energy consumed in Texas comes from wind-driven generators (**FIG. 1**), and if one-fifth of those turbines experienced blade failures, then only 2% of Texas' power generation shortfall could be blamed on the failure of wind power. The remaining total shortfall would probably be rooted in human oversights, shortcuts, a culture of risk-taking or other failings. Unless, of course, Texans are perfect. HP

HEINZ P. BLOCH resides in Montgomery, Texas. His professional career commenced in 1962 and included long-term assignments as Exxon Chemical's Regional Machinery Specialist for the U.S. He has authored or co-written more than 770 publications, among them 23 comprehensive books on practical machinery management, failure analysis, failure avoidance, compressors, steam turbines, pumps, oil mist lubrication and optimized lubrication for industry. Mr. Bloch holds B.S. and M.S. degrees (cum laude) in mechanical engineering from the Newark College of Engineering (NCE). He is an ASME Life Fellow and was awarded lifetime registration as a Professional Engineer in New Jersey. He is one of 10 inaugural inductees into NCE's Hall of Fame, which honors its most distinguished alumni.

THORBJOERN FORS, EXECUTIVE VICE PRESIDENT
Energy Industrial Applications, Siemens Energy, Finspång, Sweden

Technology to drive decarbonization of the oil and gas industry

THORBJOERN FORS is the Executive Vice President (EVP) of the Siemens Energy's Industrial Applications division. Prior to this position, Mr. Fors served as Chief Executive Officer of the service distribution generation and oil and gas business unit of Siemens. He has also held EVP roles in the organization's industrial power generation and compressions business and within global marketing and sales of new equipment, including industrial gas turbines, industrial steam turbines and power plant solutions.

Mr. Fors is a mechanical engineer with more than 25 yr of international experience in business development, sales, operation and leading global profit and loss units. Over his 17-yr career at Siemens, he has held several senior management positions in both new equipment and customer service. Prior to joining Siemens, he held a variety of leadership positions at ABB Power Generation and ALSTOM in Sweden, Australia and Canada.

Hydrocarbon Processing (HP) was pleased to speak with Thorbjoern Fors (TF), EVP of Industrial Applications, Siemens Energy, to discuss the decarbonization of the oil and gas industry and the technologies that are helping companies meet their sustainability goals.

HP: Many regulations and initiatives are being enacted by companies and countries to decarbonize. How does your organiztion see the future of the oil and gas industry?

TF: There is no question that the world is moving toward a low-carbon future. While this transition will not happen overnight, I see many organizations—from the upstream to the downstream—already making excellent progress in decarbonization. Hydrocarbons, particularly natural gas, are needed to meet the growing demand for power and for many derivative products and fuels society uses every day. I think the industry is becoming more diligent about reducing emissions and I am encouraged by the momentum.

HP: What technologies and steps can advance the processing industry's efforts to decarbonize?

TF: There are several. At the top of the list are increased electrification and power system hybridization, waste heat recovery and co-generation, and hydrogen co-firing in gas turbines. All are commercially proven and have broad applicability in the process industry. For example, Siemens Energy partnered with Braskem in Brazil to modernize the onsite power plant for a major petrochemical complex using our proprietary industrial gas turbines. The new cogeneration plant is fueled by residual process gas with high hydrogen content and will reduce energy consumption by an amount roughly equivalent to a city with 1 MM inhabitants.

Another example is in Canada, where we partnered with TC Energy to build a first-of-its-kind, waste heat-to-power facility that will convert waste heat from gas turbine exhaust at a compressor station into emissions-free power. The energy produced will be enough to electrify more than 10,000 homes and offset 44,000 tpy of greenhouse gases.

HP: Can you detail the three dimensions of the decarbonization journey?

TF: The first dimension—or step for decarbonization—is to target energy efficiency increases by better utilizing waste heat and optimizing plant performance—i.e., the "low-hanging fruit."

The second dimension involves a fuel shift—ideally away from feedstocks like coal and heavy fuel oils—to cleaner alternatives, such as natural gas, hydrogen (co-firing), biofuels and other sustainable alternatives like e-methanol. This could also mean hybridizing onsite power generation by supplementing conventional sources with renewables and energy storage.

The third dimension alludes to measures that can enable organizations to achieve deep decarbonization. This includes technologies such as carbon capture, storage and utilization and the burning of up to 100% hydrogen fuel in gas turbines to produce carbon-free power, and, of course, renewables such as wind power.

While the end goal for many organizations is the same (i.e., net-zero), the journey through the three dimensions looks different for everyone.

HP: How can digital technologies help companies meet their sustainability goals?

TF: Plant optimization goes together with digitalization. Today, operators have access to a host of digital technologies that can enhance the energy efficiency of their equipment and processes. For instance, a 1%–2% efficiency increase in a gas turbine can reduce annual carbon dioxide (CO_2) emissions by thousands of tons per year.

The Shanghai Orient Champion Paper Manufacturing Center is a good example. After considering several options, the customer selected two of our gas turbines to generate clean power. The result was 24% less energy consumed, a 60% decrease in CO_2 emissions and an annual savings of approximately 20%.

Additionally, operators can reduce unplanned shutdowns and minimize emissions associated with venting and de-inventory by improving equipment uptime through performance analytics or remote diagnostic services.

HP: With advancements in new digital technologies to optimize plant operations, how can companies protect their systems from cyberattacks?

TF: The cyberattack on a Saudi Arabia refinery a few years ago demonstrates the aggressive nature of hackers who openly target critical energy infrastructure. While the attack was unsuccessful, a holistic view that involves securing both physical operations and software is vital.

Visibility is the ultimate challenge the process industry faces because equipment operators cannot mitigate cyberattacks they cannot see. We have partnered with another organization to address the visibility gap by developing a novel end-point monitoring and protection system that uses artificial intelligence (AI) to detect and thwart attacks across a network. Incorporating these types of advanced systems as part of a layered, defense-in-depth strategy makes it possible to secure a facility and safely leverage digital technologies.

HP: Digital tools and technologies are nothing without people. How can people and digital tools co-exist to increase plant safety, productivity and profitability?

TF: You are absolutely right. At its core, digitalization is about empowering people to make more informed decisions and connecting the dots with data-driven insights. It is also about enabling new ways of working—for example, transitioning from reactive to predictive maintenance or moving towards unmanned operations by shifting resources to remote control centers.

We recently partnered with the Massachusetts Institute of Technology on a report—*Transforming the energy industry with AI*—that shows how oil and gas companies are using AI for automated monitoring and detection of cyberattacks. While the report discusses the increased need for companies to digitally transform their businesses to remain competitive and secure, one of the key takeaways is realizing that digital transformation is not something any organization can achieve independently. The human element of collaboration and partnerships are critical to success. HP

L. J. GRAHAM
Seeq Corp.

Leading in times of uncertainty

LISA GRAHAM is Chief Operating Officer (COO) for Seeq Corp. Prior to taking on the COO role, she led the analytics engineering team at Seeq Corp. She holds a PhD in chemical engineering and is a registered professional chemical engineer. With more than 20 yr of experience across many industries, including pharmaceuticals, life sciences and specialty chemicals, Dr. Graham's technical strengths include chemical engineering, product development and process model development. She has a strong business background established through executive-level leadership positions, including COO and SVP roles at Bend Research (now Lonza) and Alkemy Innovation, which she founded. Active in STEM education initiatives, she has served as Director on the Oregon Governor's STEM Investment Council and as Chair of the Oregon Board of Trustees for Oregon Tech University.

I recently gave a presentation at the American Fuel and Petrochemical Manufacturers (AFPM) Women in Industry event, where I spoke to more than 100 attendees on leading during uncertain times. My talk focused on what I believe are key leadership themes, and how those differ when a crisis strikes, as with pandemics and other "black swan" events. These types of crises stretch and grow us, forcing us to make choices we never thought we would be faced with, while determining the types of leaders we want to become.

Navigating our relationship with risk. When I asked the AFPM Women in Industry group what they think of when they hear the phrase "leadership in times of uncertainty," many used words like "listening," "empathy," "communication" and "inspiration." As women, we are leaders in our industries, communities, educational endeavors and family lives. Each of these areas of life are different, yet we have the ability to listen, empathize, communicate and inspire in every one of them. The group was adept at identifying these skills as the cornerstone of how we lead through any challenge. Now, we must lean on those abilities more than ever while taking risks, building a healthy network and communicating to drive alignment.

The first topic we explored was taking risks. When I asked the group what they picture when they hear the word "risk," many said "failure," "danger," "reward," "opportunity," "vulnerability" and "fear of potential mistakes" (FIG. 1).

All of these descriptions are true, and more than one can be true at the same time. We have all taken risks, for better or for worse, and we have all experienced failure. However, by taking those risks we have acquired new skills and experiences, preparing us to better lead in a crisis. Calculated risk-taking is actually the foundation of a good leader.

When we look back at our lives, it becomes clear that all of us have taken a series of risks to get to where we are today. We went out and pursued an education to enable us to succeed in traditionally male-dominated fields, often at great cost and with substantial time commitment. We chose jobs that would give us the experience we needed to reach our career goals. Throughout this journey, we have shared our ideas, and there is certainly risk in that, as it can open up one to criticism. Beyond sharing what we think, we also navigate day-to-day risks, such as where we sit in a meeting and when we speak.

I took a risk by coming to Seeq and growing the analytic engineering team.

FIG. 1. Risk means different things to different people, but many associate the word with negative outcomes. Figure courtesy of Seeq.

One of my goals has been to always encourage our team members to freely share their ideas. This has proved to be an effective strategy as we have navigated the COVID-19 pandemic. When travel came to a screeching halt, we were forced to pivot our entire training model.

Our team sprang into action to create a comprehensive virtual training program, enabling our organization to reach our customers anywhere in the world, while accommodating their different learning styles. It was absolutely a risk, but we had to try—and our efforts netted success. We completed more than 300 virtual trainings in 2020, often with 50–100 attendees per session, and 2021 promises more of the same.

The power and promise of networking. Another key element of leading during uncertainty is networking. While most people think of networking in the context of a social event, business networking is based on trust and energy, both of which are imperative for leading during a crisis.

How do we build the type of network that goes beyond swapping business cards? It is not easy and, when asked, many in the group said the hardest part is following up and maintaining relationships, without interactions feeling forced. However, when we shift our mentality to a focus on building trust and energy, we take the long view. Trust evolves with time, from initiating a relationship to developing and sustaining it. We build that trust by doing what we say we will do, and by showing that we have the best interest of everyone on the team in mind.

One of the greatest ways we can network to build trust is to be an energizer. Energizers create enthusiasm, in part because they engage in a set of foundational behaviors that build trust. Energizers approach situations with a clear head, giving them the endurance to lead.

When you interact with an energizer, try not to worry that you will be judged, dismissed or devalued. Without fear of rejection, it is easier to share fledgling ideas or novel plans—to innovate, take risks and think big. Energizers create trust, but trust is not all they create. The real power of energizers is that they enable others to realize their full potential.

While taking risks and networking to build trust and energy are critical to leading during uncertainty, ultimate success hinges on combining these endeavors with effective communication and leading by example. We must align our teams and our customers toward a common goal so that we can make efficient and effective progress. In addition, we must be willing to take the risk of putting our own ideas out there for the entire world to see. After all, in every crisis there is an opportunity to consider new and exciting ideas to pave new paths, elevate team members and reap the rewards of hard work and ingenuity.

Lastly, I thank each and every woman who participated in the AFPM Women in Industry event. Their feedback and willingness to engage in discussion made the risk I took to speak pay off. The organizers did a fantastic job, and it was a terrific experience overall. I am grateful for the opportunity, and I cannot wait to see the impact each of them will have on their teams, their companies and the industry as a whole. HP

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Converting a petroleum diesel refinery for renewable diesel

As refiners consider renewable, low-carbon alternatives, renewable diesel—refined from agricultural products using petroleum refinery processes—is gaining traction. Rather than constructing new grassroots renewable diesel production units, refineries with existing hydroprocessing units may be able to increase their speed to market with conversion projects.

The use of fossil hydrocarbons has fostered growth and prosperity more than any other fuel resource in modern times. Today's stronger focus on environmental, social and governance issues have driven interest in more sustainable alternatives. Renewable diesel is on the rise among those who seek renewable and sustainable transportation fuels.

Renewable diesel is refined from agricultural products, particularly vegetable oils, waste cooking oils and animal fats that are sustainable and available. Because it uses the same hydrotreating and separation processes used for petroleum diesel, it employs the same basic infrastructure and equipment. Renewable diesel does not contain oxygen, eliminating the freezing, storage and blending challenges associated with other renewable fuels, such as biodiesel. Because renewable diesel has the same chemical structure as petroleum diesel, it can be used in engines designed to run on conventional diesel fuel—a "drop-in" diesel substitute with no blending limit.

Making the grassroots vs. conversion decision. The question refiners interested in renewable diesel are asking is whether to build a new renewable diesel plant or convert an existing hydrotreater unit.

For many, the answer may seem simple. Refiners often realize multiple benefits by converting an existing refinery hydrotreater unit rather than constructing a grassroots plant. Perhaps the most significant is time savings. A typical renewable diesel conversion project can be completed in approximately two years, or roughly half the time needed to design and build a new grassroots unit.

Because the power, water, waste, utility and flare systems needed to support a hydrotreater for renewable diesel are already present in a refinery, a conversion project will cost less than a grassroots project. A renewable diesel plant on a greenfield site will require the addition of this new infrastructure.

Even more than initial construction cost savings, the greater financial benefit of a conversion project is the ability it gives a refiner to get renewable diesel products to market more quickly.

The largest market for renewable diesel fuel in the U.S. is California, where credits from the federal Renewable Fuel Standards program in combination with California's Low Carbon Fuel Standards (LCFS) help make it cost competitive. At least 18 other states and Washington D.C. have legislation in place for transportation fuel standards comparable to California. The refiners who are first-to-market in these states will be the biggest beneficiaries of fuel credits. Once the market is saturated, credit availability will likely decline.

However, time-to-market is not the only factor to consider when choosing whether to convert an existing unit or build a new one. To determine if an existing unit is a good fit for a conversion, it is important to evaluate the condition and usability of its existing equipment and ancillary systems. Process simulations and other analysis will likely be needed to demonstrate the viability of a conversion project. Some factors to consider include:

- **High reaction exotherm**—Whether using agricultural waste or crude oil, a hydrotreater's reaction releases heat when breaking chemical bonds in the feedstock. However, renewable diesel reactions are significantly more exothermic than petroleum diesel desulfurization reactions. Therefore, it is important for these units to be equipped with high liquid product recycle capacity that can be used to absorb this heat. It is also necessary to recalibrate production expectations based on the high product recycle through the unit. A hydrotreater that operates at 50,000 bpd for petroleum diesel production may only be able to accommodate 5,000 bpd of fresh feed when converted to renewable diesel.
- **Emergency depressurization systems**—Because of the high heat release associated with renewable diesel reactions, hydrotreaters require emergency depressurization systems to manage the reaction safely in the event the recycle and quench systems fail. These systems quickly depressurize the reactor to a flare, stopping the reaction.
- **Hydrogen consumption**—Renewable diesel reactions consume a significant amount of hydrogen. Therefore, refineries with excess hydrogen capacity are particularly good candidates for conversion projects. Refineries with limited hydrogen availability may need to budget for the construction of an additional hydrogen plant.
- **Feed train considerations**—Depending on the quality of the renewable diesel feedstock, it may be necessary to upgrade the metallurgy in the unit's feed train system. For example, feedstock that is high in free fatty acids

has the potential to create a corrosive environment. Another special consideration for renewable feedstocks is the potential for polymerization in the feed train. When hydrogen is absent, renewable feedstocks can polymerize, which causes gumming and fouling in the equipment. The addition of hydrogen could make the equipment susceptible to high-temperature hydrogen attack. One option is to update feed-side metallurgy to protect against corrosive conditions. Another is to create two separate pre-heat trains, with separate systems for liquid recycle and fresh feed.

- **Water and carbon dioxide (CO_2) production**—Renewable diesel reactions produce water and CO_2 in much larger quantities than petroleum hydrotreaters, creating potential carbonic acid corrosion concerns downstream of the reactor. Metallurgy upgrades may be required in the reactor effluent air cooler system. Consideration must be given to the handling, treatment and disposal of the extra water and CO_2 produced in these reactions. For example, if water is routed to the refinery's sour water stripper, it may produce high concentrations of carbonic acid in the sour water streams, impacting how the water is treated and reused.
- **Heat tracing**—The vegetable oils and animal fats used as feedstock become waxy and solidify at ambient temperatures. To load them into trucks and rail cars for shipment and, later, unload and charge them to a hydrotreating unit, these feedstocks must be in liquid form. That requires steam or electric heat tracing systems that raise the temperature of pipes, tanks and vessels to liquefy the fats and oils. The addition of significant heat tracing capacity will likely be required for both existing hydrotreating infrastructure, as well as the rail, truck or barge piping and equipment used to store and transfer feedstock into the unit.

Any of these factors could potentially give a refiner pause on a renewable diesel conversion project. More likely, they will provide insight on the right way to move forward.

As they proceed, refiners must be prepared to face issues beyond these technical considerations. In an LCFS environment, renewable diesel projects must be able to account for the carbon they emit. Therefore, refiners must approach these projects holistically, measuring carbon intensity at every step along the path. From the farm fields to the end product's final delivery, producers must look for ways to lower the carbon intensity at each step.

Despite these challenges, the transition to renewable diesel will continue. The time for refiners to consider their options is now. HP

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Reducing acid consumption: Maximizing sulfuric acid alkylation unit profitability

Alkylation is a process used to produce highly branched isoparaffins from the reaction of lighter olefins and isobutane in the presence of sulfuric acid as a catalyst. This highly branched isoparaffin is called alkylate—a blending component that constitutes approximately 10%–15% of the gasoline pool in the U.S. Besides the ability to increase octane and lower Reid vapor pressure (RVP) in the gasoline pool, alkylate also reduces vehicle exhaust emissions with zero olefins, zero aromatics and low sulfur.

Alkylate margins have been very healthy worldwide over the past 10 yr. The gross margins (alkylate value minus feedstock cost) for the U.S. Gulf Coast have ranged from a low of about $20/bbl to more than $70/bbl over this period, with an average of approximately $40/bbl. There are seasonal dips in profitability, and, although the COVID-19 pandemic has taken its toll on gasoline demand worldwide in 2020 and early 2021, alkylation is yielding strong margins as gasoline demand increases.

To capitalize on high alkylate margins, refiners have been maximizing throughput and pushing alkylate production well beyond design capacity. While units are enjoying increased profitability from increased alkylate production, acid regeneration costs are also rising. In the spirit of efficiency, operating alkylation units are being asked to make more alkylate with less acid. Refinery budgets and planning groups are requesting a reduction in acid consumption, while maintaining (or even increasing) alkylate throughput. How to reconcile this conundrum of more with less? First, we must explore the relationship that acid consumption has with alkylation unit operating variables.

New alkylation units running at design conditions typically consume 0.2 lb–0.4 lb of sulfuric acid per gallon of alkylate produced (FIG. 1). However, when units are pushed beyond initial design capacities, acid consumption rises due to bottlenecks such as lack of cooling, low isobutane-to-olefin (I/O) ratios and high space velocities within the reaction zone. In addition, older units are not typically instrumented well and many lack modern technology design improvements. With overloaded units, the acid consumption can be two to three times higher than in an equivalent new unit design, and the cost of acid regeneration can surpass 50% of the utility and chemical costs of the alkylation unit.

This article discusses strategies that can be implemented by refiners to help lower the sulfuric acid consumption of the alkylation unit.

Contributors to acid consumption. Numerous factors contribute to the acid consumption in an alkylation reaction. These include the olefin feed type, feed contaminants, reaction zone I/O ratio, diluents, reaction temperature, mixing intensity, acid entrainment losses and the acid spending range.

Olefin feed type and feed contaminants. Fluid catalytic cracking (FCC) butylene (especially isobutylene) has the lowest acid consumption among olefins. When refineries decide to alkylate more propylene, amylene or feeds with higher levels of contaminants, they experience increases in acid consumption. Butadiene, pentadiene and cyclopentene contaminants in the olefin feed can double overall acid consumption in the unit. Other feed contaminants (e.g., sulfur compounds) can increase it, as well.

I/O ratio and diluents. The I/O ratio is another factor that affects the acid consumption. As the I/O ratio decreases, acid consumption increases. When fractionation towers reach their limits, isobutane purities go down and reaction zone diluents such as propane and n-butane go up, which increases acid consumption and reduces alkylate quality. Increased normal butane content in the refrigerant reduces reaction zone cooling.

Reactor temperature. Increasing feed rates to the alkylation unit increases the overall heat of reaction. This heat of reaction must be rejected within the refrigeration system to maintain

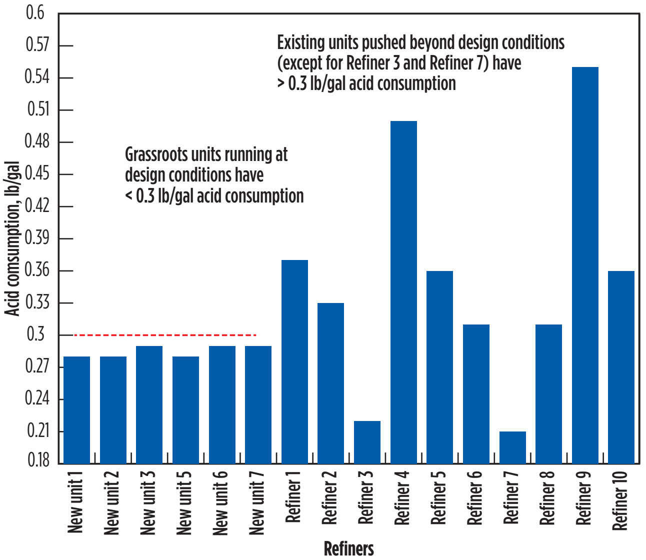

FIG. 1. Reaction acid consumption (lb/gal alkylate) for recent grassroots units and older operating units.

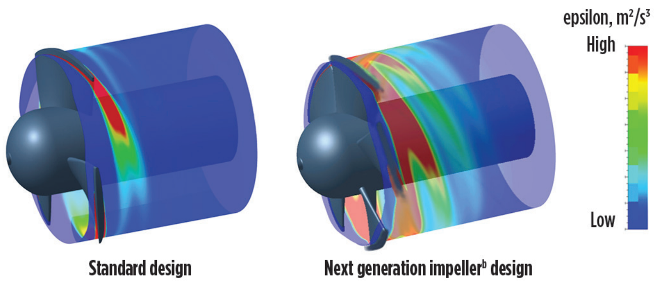

FIG. 2. Turbulence dissipation rates of standard three-blade vs. next-generation impeller[b] design.

optimal reaction temperatures. When units are pushed beyond the refrigeration system capacity, the reactor temperature will rise above the optimum value of 5.6°C–7.2°C (42°F–45°F). At higher temperatures, acid consumption and corrosion can increase dramatically. Most refiners set a maximum reaction temperature limit [e.g., 15°C (60°F)] to maintain acceptable corrosion rates. To lower the reaction zone temperature, first ensure that the existing refrigeration system is running at its full potential. Then, consider reactor enhancements (such as tube inserts, 0.75-in. tube bundles and proprietary internal modifications[a]) and/or refrigeration upgrades (such as supplemental chillers or compressor modifications).

Acid entrainment. Acid settlers without coalescing media experience higher acid entrainment losses in the hydrocarbon effluent, especially as alkylation unit throughput increases. Acid carryover can also lead to corrosion of downstream equipment. To minimize acid entrainment losses, coalescing media can typically be retrofitted on older acid settlers. Higher acid inventories in the reaction zone promote negative side reactions that degrade the alkylate product quality and increase the acid consumption. Most modern units have smaller acid settlers with coalescing media that allow for both reduced acid inventory and less acid carryover.

Acid spending range. Acid spending that ranges from 99.2% fresh acid strength down to 90% spent acid strength makes it possible to extract maximum value from the acid before it is sent off to regeneration. Modern unit instrumentation, along with good lab practices, are essential to ensure that the differences between actual and target acid strengths are minimized to reduce acid demand. Units with best-in-class monitoring systems can safely reduce spent acid strength below 90 wt%, resulting in significant acid savings.

Mixing intensity. Units with less mixing intensity (hp/bbl alkylate) typically consume more acid and produce lower-quality alkylate. If impellers are worn or the speed is reduced, unit performance degrades. Reaction temperature can increase with less mixing due to lower heat transfer, as well. Add-ons, such as next-generation impellers[b] and proprietary internal modifications[a] (**FIGS. 2** and **3**), increase turbulence and mixing, and reduce acid consumption.

Refiners' options to reduce acid consumption.

The following are ways that refiners can reduce acid consumption within their alkylation units.

Spent acid strength. Many refiners operate at a spent acid strength higher than the design or target spent acid strength, thus "giving away" acid. Operations personnel almost always err on the side of caution to avoid an acid runaway, as there are typically minimal consequences in wasting acid, but significant consequences for a low acid strength excursion.

Much of this acid waste has to do with the delay time and inaccuracy of acid strength lab results. If the results for an acid sample come back and are falsely low, what is the operations team to do? It will generally crank up the fresh acid rate and retest the samples. The longer it takes to get a sample back, and the less accurate the lab results, the more acid is wasted.

Since acid costs can be very significant, it makes sense to spend effort on streamlining acid sampling, delivery and lab procedures to achieve a quick and accurate turnaround. Many refinery labs do not centrifuge the acid samples, which contributes to misleading results—typically 0.5 wt%–1 wt% lower than actual. Sometimes, labs will let the samples sit for a couple of hours to decant the hydrocarbon. Decanting is less effective than centrifuging—possibly allowing more time for humidity to contaminate the sample and, thus, delay the reporting of the results.

Operations should be diligent in challenging its lab personnel for quicker and more accurate results, since so much money is at stake. It is also a good idea to periodically "blind test" the lab with identical triplicate samples to find the standard deviation (SD). For example, the authors' lab's SD is less than 0.03 wt% for triplicate samples. A refinery does not typically require this level of accuracy; however, reducing SD to about 0.2 wt% can allow refiners to confidently spend closer to the target strength and realize significant acid cost savings. A centrifuge and good lab techniques are very inexpensive by comparison.

Reduce feed contaminants. Dienes (butadiene, pentadiene, etc.) are common contaminants in the alkylation unit feed stream. If the total diene concentration within the olefin feed is greater than 0.5 wt%, or if acid costs are especially high, consider sending the olefin feed to a selective hydrogenation unit to remove these contaminants.

High water content in the olefin feed can also impact acid consumption but can be removed by a properly designed feed preparation section (feed/effluent exchanger and feed coalescer). The feed should be cooled as much as possible [typically down to approximately 13°C (55°F)] in the feed/effluent exchanger to reduce the solubility of water in the hydrocarbon phase. This allows more water to drop out in the downstream feed coalescer. Modern units with dry alumina treating and dry recycle isobutane typically do not need a feed coalescer, as there is no free water to remove.

Process optimization. Process optimization is the first step toward reducing acid consumption, and it offers multiple variables that can be adjusted. In general, it is the temperature and I/O ratio that have the biggest impact on acid consumption.

The first strategy is to maximize heat removal from the system to lower the reaction temperature closer to 7.2°C (45°F). Due to refrigeration limitations, it is not always possible to reduce the temperature for units operating over design capacity. However, there are often "low-hanging fruit" refrigeration issues that have been overlooked. Before spending money on improvements, make sure that the refrigeration system is running as efficiently as possible. Items to review include:

- Ensuring that the compressor anti-surge valve is completely closed with no bypassing. Check that the

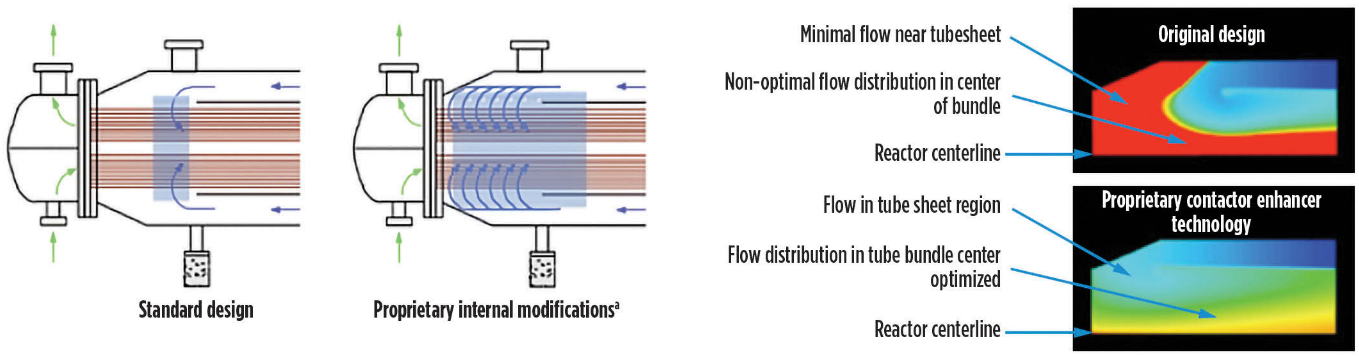

FIG. 3. Improvements in the proprietary contactor flow regime over a standard design.

downstream side of the valve is at ambient temperature. Anti-surge flow wastes significant compressor power.

- Each incremental 1 psi of line loss between the suction trap and the compressor inlet raises the reaction temperature by approximately 1.4°C (2.5°F). Verify that the mist eliminator in the suction trap was designed for a low pressure drop (about 0.1 psi) and is operating properly.
- For units with fixed-speed compressors, make sure that the suction throttle valve is 100% open. This valve should be full line size with low pressure drop (approximately 0.25 psi).
- For units with variable-speed compressors, ensure that the driver can operate at full design speed. Sometimes, this requires cleaning of the steam turbine and piping to remove salts.
- Check that the cold sides of the condensers are clean and operating as designed. These exchangers are critical and should receive special attention. Hot vapor bypasses should be closed to minimize condensing pressure.
- Trend and optimize the refrigerant propane content to find out at what value the refrigeration system works best. This is typically a trial-and-error process.
- Refrigeration systems can be poorly designed. Review your system and its controls with an expert. Consider a system revamp to increase heat removal.

It is important to remember that there is no one-size-fits-all strategy to improve a unit's performance or capacity. The refiner's goals should be understood in terms of maximizing alkylate capacity or quality, or minimizing operating costs such as acid consumption.

Case studies.

A series of case studies were used to determine economics for the various aftermarket options that many refiners use to increase refrigeration.

Tube inserts. Tube inserts increase the heat transfer by distributing equal amounts of refrigerant to each tube in a tube bundle. They typically lower the reactor temperatures by 2.2°C (4°F) at a fixed olefin feed rate. When two-phase effluent enters the tube bundle channel head without inserts, the vapor separates and causes some tubes to operate hotter due to higher vapor content. This results in reduced overall heat transfer. Tube inserts eliminate vapor separation in the channel head by maintaining enough pressure on the effluent to keep it liquid until it flashes within the tube inserts.

0.75-in. tube bundle. A 0.75-in. tube bundle provides approximately 35% more heat transfer area compared to a 1-in. tube bundle. The additional heat transfer area reduces acid consumption by reducing the reactor temperature approximately 3.3°C (6°F) at a fixed olefin feed rate.

Tube inserts and 0.75-in. tube bundle. Combining a 0.75-in. tube bundle with tube inserts reduces the reaction temperatures by about 4.4°C (8°F) at a fixed olefin rate.

Proprietary internal modifications[a]. These design changes improve the flow regime within the reactor (**FIG. 3**). In the standard design, emulsion flow leaves the annulus between the reactor shell wall and circulation tube, then turns 180° to flow across the tube bundle 3 ft–4 ft (approximately 1 m) in front of the tube sheet.

Results from computational fluid dynamic studies showed that the standard design has low velocities and, therefore, low heat transfer near the tube sheet. To remedy this, the circulation tube was extended, and a flow distributor was added for better use of the entire tube bundle heat transfer surface area. This improves heat transfer and lowers the reaction temperature by approximately 1.7°C (3°F) at a fixed olefin rate.

Feed and refrigerant chillers. Several refiners have supplemented their existing refrigeration system with packaged chillers that remove incremental heat from the reaction zone. Typically, these chilling units cool glycol, which then cools the reactor feed and/or the condensed refrigerant. They are not as efficient as a properly designed primary compressor, especially if an intermediate heat transfer fluid is used. However, these chilling units can be rented (or permanently installed), and they offer a relatively easy path to increased alkylate capacity.

A series of unit simulations were completed to demonstrate the economics of various unit options. The results are detailed in **TABLE 1.** The following are the details of each simulation case:

- **Design Case:** This was for a 16,000-bpd alkylation unit operating at the ideal design condition reaction temperature [7.2°C (45°F)].
- **Operating Case:** The same unit pushed to produce more than 21,000 bpd of alkylate, while staying within the refiner's reaction temperature limit of 15.6°C (60°F). Acid costs increase dramatically, but unit profitability increases by almost an order of magnitude more. Therefore, refiners typically push their alkylation units.
- **Performance Optimized Operating Case:** This case is the previous case with extra attention devoted to

TABLE 1. Economics evaluation using $150/t of acid cost and $25/bbl of alkylate margins

Description	Temperature	Acid flow, tpd	Alkylate rate, bpd	Acid consumption, lb/gal	Acid cost, $/d	Alkylate margin, $/d
Design Case	7.2°C (45°F)	101	16,000	0.3	15,120	400,000
Operating Case	15.6°C (60°F)	209	21,142	0.47	31,301	528,550
Operating Case—Performance Optimized	14.4°C (58°F)	182	21,142	0.41	27,305	528,550
Reactor Improvements Case	11.1°C (52°F)	155	21,142	0.35	23,309	528,550
Reactor Improvements with Increased Feed Case	15.6°C (60°F)	210	23,275	0.43	31,526	581,875

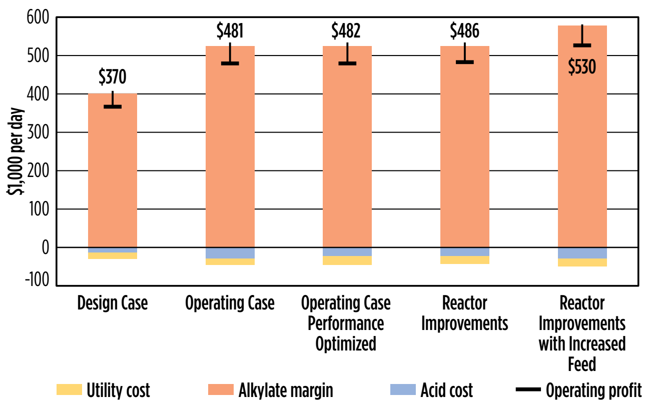

FIG. 4. Alkylate operating economics using $150/t of acid cost and $25/bbl of alkylate margins, electricity cost of $0.05/kWh, steam 15# as $3/MMBtu, steam 150# as $4/MMBtu, and steam 225# as $5/MMBtu.

optimizing refrigeration section performance and to managing spent acid analyses and control to lower acid consumption. The alkylate rate was kept the same, so acid consumption dropped.

- **Reactor Improvements Case:** This case included tube inserts, 0.75-in. tube bundles and the proprietary internal modifications and assumes that the refrigeration section and spent acid management are optimized. Chillers were not included. Acid consumption drops even further at the same alkylate capacity.
- **Reactor Improvements with Increased Feed Case:** This case is the real moneymaker. It is the same as the previous case but assumes that refiners will maximize the alkylate rate until they hit the reaction temperature limit. Although the acid consumption is almost double the design case, the profitability of the incremental alkylate more than makes up for the additional cost.

When looking at **FIG. 4,** it is easy to understand why most North American refiners continuously push their alkylation units far beyond the original design capacity. The case studies demonstrate that the earnings from conservative alkylate margins greatly outweigh the extra cost of sulfuric acid demand.

The Operating Case—where the unit was operating at its current refrigeration limit reaction temperature [15.6°C (60°F)]—generates a $128,000/d additional alkylate margin, while costing only $15,000/d more on acid than the Design Case. This is a net profit gain of nearly 30%.

After optimizing the refrigeration section operations and better managing acid analyses and control, it is typical to reduce the acid consumption by 10%–15%. The Performance Optimized Case saves $4,000/d on acid cost vs. the Operating Case. Most refiners would likely use the 1.1°C (2°F) reaction temperature decrease to produce more alkylate.

With the Reactor Improvements Case (tube inserts, 0.75-in. bundle and proprietary internal modifications), refiners could save $8,000/d on acid cost at the same alkylate capacity, but would probably take advantage of the cooler reaction temperatures to process more feed.

With increased feed, the alkylate margins increase to $180,000/d, showing why refiners continue to push their units. This case boosts the net profit gain to 43% vs. the Operating Case. By adding in all reactor enhancements and pushing temperature limits, the unit is nearing 150% of the design capacity.

Takeaway. Every sulfuric acid alkylation unit refiner should tackle this low-hanging fruit to get more cooling out of their existing refrigeration section and to better manage their acid analyses/control to reduce consumption. Acid consumption savings of 10%–15% are typically achievable through extra attention to unit operations and with only minimal investment. The value of additional alkylate typically far exceeds the incremental cost of spent acid, so, when changes are made that lower reactor temperature, refiners usually take advantage of the improvement to produce more alkylate. This explains why acid consumption for most older units far exceeds new unit design values. HP

NOTES

[a] STRATCO® XP2 technology
[b] STRATCO® ST-M impellers
[c] STRATCO® Contactor™ reactor technology

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Leveraging digital technologies to create the smart renewable diesel facility

Many companies are modifying existing crude refineries or building grassroots renewable diesel facilities to produce drop-in, green renewable diesel from a variety of agriculturally derived triglyceride feedstocks. The key drivers for this global trend are regulatory, tax and social pressures to lower the carbon intensity of transportation fuels.

The renewable diesel production process offers many challenges that can impact safety, reliability and profitability. These challenges range from feedstock availability, variability, gumming, metals, corrosion and wax formation in the pretreatment unit (PTU) or feed pretreatment train that can affect safety, operability, catalytic-based yield and profitability of the renewable diesel unit (RDU). The RDU also has a high-reaction exotherm and is vulnerable to several types of corrosion, such as high-temperature hydrogen attack (HTHA), which can be addressed using approaches such as analytics, integrity operating windows, real-time decision support and automated safety shutdown systems.

Companies that are moving into the production of renewable diesels can mitigate the safety and processing challenges in the PTU and RDU by adopting digital technologies used by leading hydrocarbon processing industry (HPI) companies. Such operators have achieved a 2%–4% increase in effective capacity by improving asset reliability; providing real-time, proactive decision support; reducing operating and maintenance (O&M) costs by 3%–5%; increasing EBITDA performance by 3%–5%; and improving safety.

These leading HPI companies are using a critical real-time data infrastructure[a] that enables subject matter experts (SMEs) to configure no-code operational digital twins[b] of asset classes (e.g., pumps and reactors) and develop smart applications like HTHA analytics. The asset class templates are then used as building blocks to create an operational digital replica of their PTU, RDU and associated supporting production infrastructure such as hydrogen sources, utilities and logistics. This digital infrastructure enables a layered approach to descriptive, diagnostic, predictive and prescriptive analytics, and provides proactive real-time, exception-based decision support.

This article will present how this leading digital technology can enable operational intelligence and continuous improvement, and also increase flexibility, capacity and profitability for renewable diesel production in both grassroots and retrofit scenarios.

The challenges of renewable diesel manufacturing: Safety, operations and profitability. Two primary approaches exist to the development of renewable diesel production. Each will be presented, with associated reasoning and a similar method for leveraging the operational data infrastructure[a].

Approach 1: Existing petroleum refinery retrofit. Companies are moving forward with modifications of existing petroleum refineries for cost, time to market, margin and best alternatives to shutting down the petroleum refinery, with the associated environmental and regulatory challenges. However, modifications of existing hydrotreating facilities and associated infrastructure present the following six challenges[1] that a real-time data infrastructure[a] can help mitigate:

1. **High-reaction exotherm and associated emergency depressurization systems and liquid recycle and quench systems**—The operational data infrastructure[a] is used by leading HPI companies to help mitigate this challenge through proactive, exception-based decision support. The operating windows (OWs) and integrity operating windows (IOWs) can be configured to combine various process parameters and to provide improved awareness of

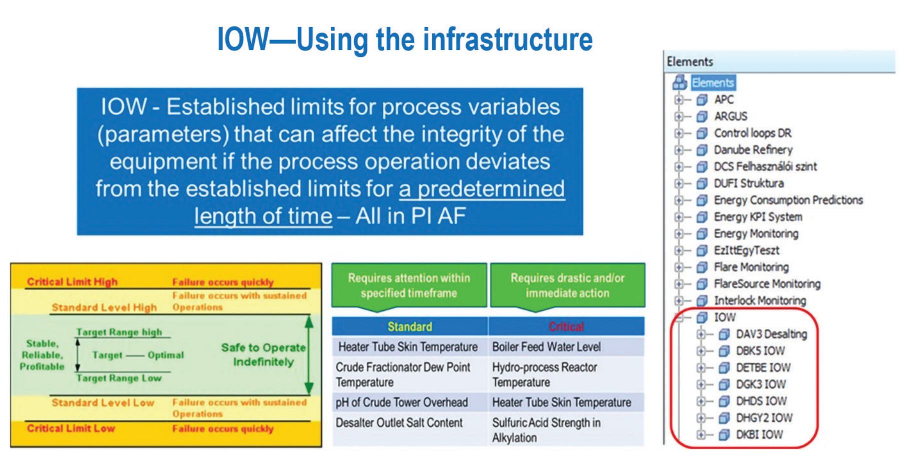

FIG. 1. Example of configuring OWs and IOWs in the real-time operational data infrastructure.[2]

the operating regimes that need attention. The difference between OWs and IOWs is the degree of criticality and the required time to respond to mitigate escalating situations, including the triggering of the emergency depressurization system. **FIG. 1** presents an example of an IOW developed and implemented by MOL, a Hungarian energy company, in its six HPI facilities. MOL developed a portfolio of OWs and IOWs based on industry standards and the experience of its SMEs, and by configuring associated OW and IOW digital asset templates. These templates are then put into production across its facilities, enabling changes to be propagated quickly and efficiently.

2. **Feed train fouling**—Managing polymerization and associated gumming and fouling to optimize asset performance is another common, powerful application of the operational data infrastructure[a], which allows the configuration of asset health indexes by SMEs to determine the health of various assets, such as pumps, exchangers, heat tracing and valves. The health indexes can then be used to incorporate indicators of possible issues, such as fouling from polymerization in the exchanger train or a drop in pump efficiency. The health index can be aggregated across the PTU and/or the RDU to roll up to a key performance indicator (KPI) on the summary dashboard, enabling drill-down and diagnostic investigation. Leading HPI companies are also integrating the health index with their maintenance management systems (MMSs) to trigger work orders and to link in metadata found in the MMS, such as the last maintenance date, spare parts inventory, or manufacturer's make and model information, which are commonly used in the health index calculation. **FIG. 2** provides an example of an advanced condition-based maintenance (ACBM) system created using a data infrastructure[a]. MOL has configured health indexes for all its critical assets (such as all rotating equipment, exchangers, crucial valves and heaters), and has integrated the indexes with its MMS.

3. **HTHA corrosion**—As with other HPI processes that utilize high temperatures and hydrogen in carbon alloy metal environments, HTHA can occur, leading to embrittlement and loss of containment. **FIG. 3** illustrates MOL's use of an HTHA smart asset template, and demonstrates how a data infrastructure[a] can address various corrosion regimes, including HTHA, carbonic acid and others. The template uses a table lookup for the regressed coefficients from the Nelson curve, which provides correlation of hydrogen and temperatures with various carbon steel alloys to determine when an alloy node is approaching or has entered an HTHA regime. The start and end of this event can be configured, which is, in effect, codification of the SMEs' knowledge. Notifications can be triggered in both cases, and analytics can determine the length of exposure and the exposure details. A similar approach can be used for any corrosion or process condition.

4. **Carbonic acid corrosion**—As a result of the conversion of triglycerides to hydrocarbons, water and large amounts of carbon dioxide are formed. Apart from these substances needing to be handled safely on an individual basis, they can combine to form carbonic acid that can be very corrosive in the liquid effluent air coolers and sour water disposal systems. To address this corrosion regime, the operational

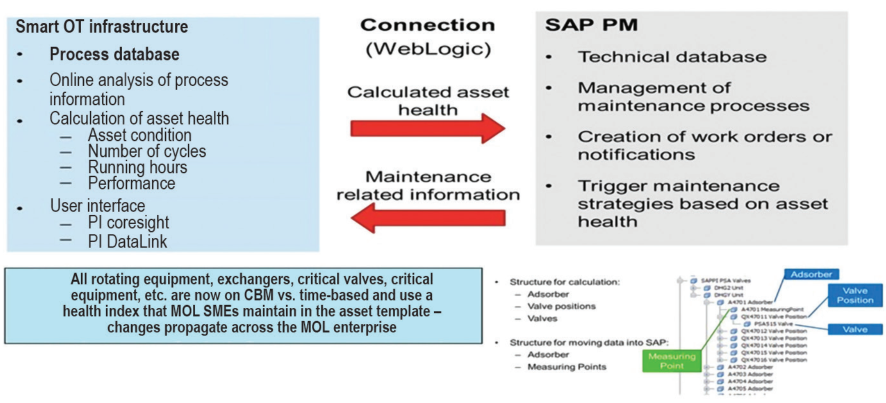

FIG. 2. Example of use of the real-time operational data infrastructure for advanced CBM.[2]

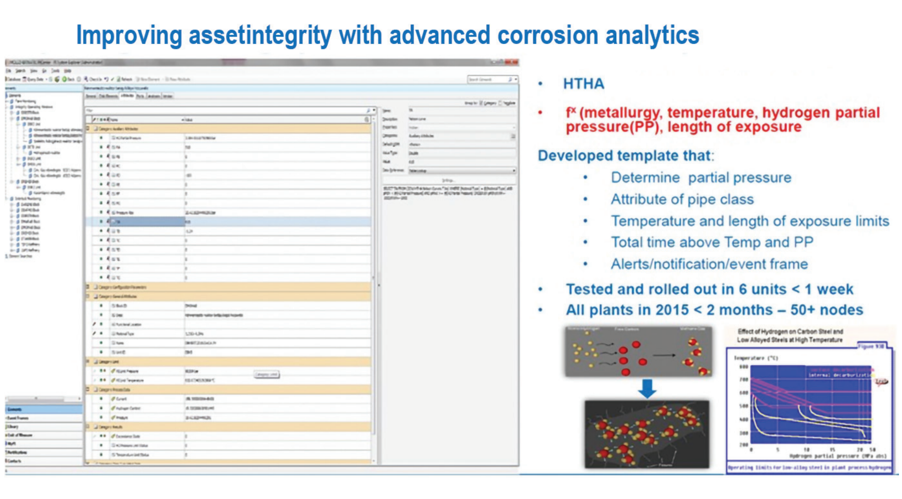

FIG. 3. Example of a configured HTHA corrosion smart asset template.[2]

data infrastructure[a] can be used to create OWs and IOWs, in addition to specific carbonic acid analytics and associated health indexes to be used to notify and proactively inform operators so that corrective actions can be taken. The start and end of events can be configured, like the HTHA application, to capture length of exposure, severity and causality to enable more effective decision making, including modifications in operations, inspection and metallurgy.

5. **Catalyst performance and associated yield optimization**—To optimize the catalyst performance and yield in PTUs and RDUs, many leading HPI companies are digitally integrating with their catalyst providers to facilitate advanced unit and catalyst performance. To address the issues of data/cybersecurity, ownership and governance, these leading HPI companies are leveraging an extension of the operational data infrastructure[a] as an enabler of this powerful capability. Instead of using other data transfer methods that are labor intensive and have variable lag times, this digital bridge addresses these issues (**FIG. 4**).

6. **Near-real-time modeling and optimization**—Another optimization approach being used by leading HPI companies is the deep integration between the operational data infrastructure and rigorous, first-principle simulation models for PTUs and RDUs, including the inclusion of financial

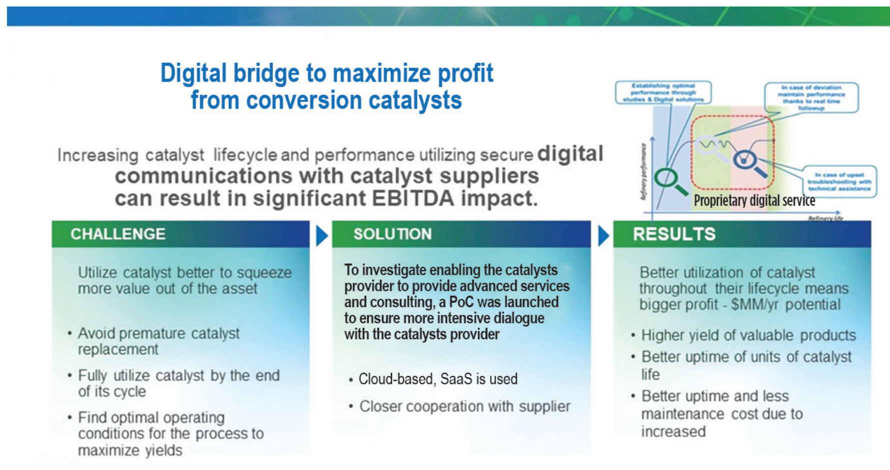

FIG. 4. Example of optimizing catalysts' performance with near-real-time remote monitoring.[3]

information. The operational data infrastructure[a] and associated smart asset templates are leveraged to provide context and validated data sets to the models. Optimum targets and forecasts are outputs of the models that are put back into the operational data infrastructure as "future data." This information is used to perform plan vs. actual analytics, and to enable proactive, data-based decision support, including key information such as lost margin opportunities, the asset heath of PTUs and RDUs, and other intelligence (**FIG. 5**).

Approach 2: A new grassroots renewable diesel facility. Many non-petroleum refining companies are choosing to design, build and operate new renewable diesel facilities that provide greater flexibility to optimize the entire facility, including feedstock sources and necessary purification in a PTU; the design and catalyst selection in the RDU; the design of the required infrastructure, including utilities, hydrogen sources, blending and logistics; and waste disposal.

The operational challenges, which are fewer because of the flexibility afforded by a grassroots design and build, are still present, and the mitigation opportunities from the use of an operational data infrastructure remain applicable. The operational data infrastructure[a] can be configured to address the challenges and opportunities of a grassroots design and build. One key advantage of leveraging an operational data infrastructure experienced by many HPI companies is the ability to accelerate startup, improve warranty validation, and reduce the number of applications and solutions by more than 50%.[5]

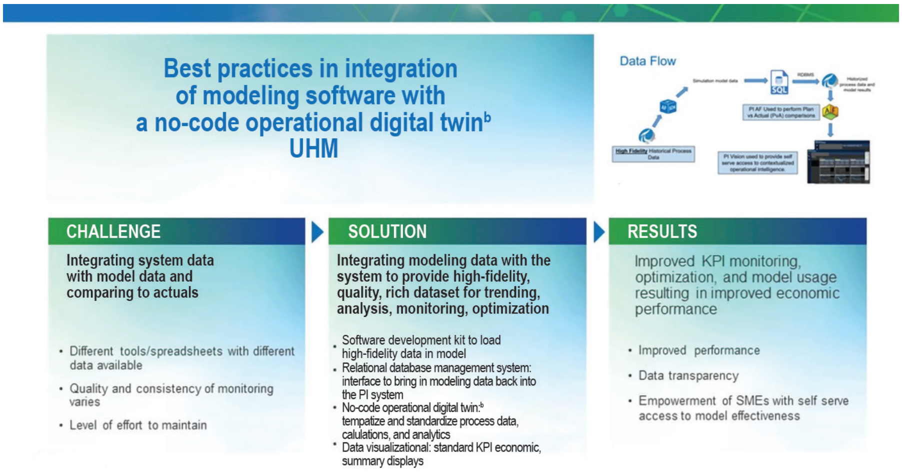

FIG. 5. Example of deep integration between the operational data infrastructure and modeling software.[4]

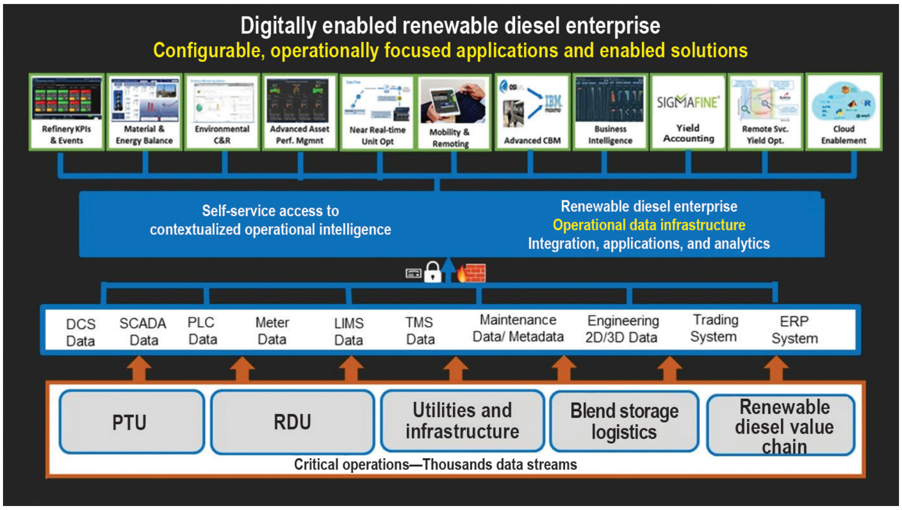

FIG. 6. A critical operations integration, applications and analytics infrastructure.

Creating the smart renewable facility with an operational data infrastructure. A real-time operational infrastructure[a] is an agnostic, open, scalable and reliable technology specifically designed for critical operations to deliver operational data in a reliable way to stakeholders and applications. The infrastructure must enable self-service analytics, deliver all required context for operational intelligence, and have the following capabilities (**FIG. 6**):

- Secure integration of time-series operational data from the distributed control system (DCS), supervisory control and data acquisition (SCADA), and Industrial Internet of Things (IIoT) systems
- Abstraction of diverse tag and asset names into a standard company lexicon and asset hierarchy
- Integration of metadata, including engineering data and information from the MMS (**FIG. 2**)
- Normalization of units of measure, time zones and asset descriptions
- Configuration of traditional operational applications, such as energy management, environmental compliance and KPI-driven dashboards
- Use of a "layers of analytics" framework and strategy to provide the analytics foundation via configurable descriptive, diagnostic and simple predictive analytics.

No-code operational digital twins[b] configured and supported by SMEs. A digital twin is a replica of a physical asset (such as a heat exchanger, pump or compressor) comprising attributes, calculations, KPIs, empirical correlations and models of varying complexity. Contrary to the hype, digital twins have been around since the 1960s. However, today's operationally focused digital twins are dramatically more robust and sophisticated in their ease of use, approach and capability to develop, evolve and leverage in a renewable diesel plant.

Most digital twins require IT, data scientists, machine learning, model integration and coding. They also have a limited ability to deal with data volume, velocity,

variability and anomalies. They are difficult to scale, and struggle to address the anomalies of physical assets that have variability in vintage, makes, models and levels of instrumentation. Furthermore, real-time operational data and asset metadata (i.e., static information like equipment model and location) typically reside as tags in control systems, as well as in other databases and platforms, with accessibility issues and lack of naming standards limiting access to critical data that could potentially be leveraged to gain insights.

A key capability of the operational digital twin is operational data management that creates a system of record for operational data. The operational digital twin is created by the SMEs over time in an evolutionary way by first creating smart asset digital templates that consist of asset categories, attributes, calculations, event frames and notifications. Attributes are grouped in categories for providing ease of navigation and enabling the drag-and-drop configuration of smart display templates. These attributes consist of data references to real-time data sources like DCS, SCADA, programmable logic controllers (PLCs) and other systems, as well as linked tables into engineering data, the MMS and tabular correlations like the HTHA example. The digital twin provides configurable, no-code calculations and complex expressions by using one or more of the more than 110 time-based functions, such as the function library in Excel.

The smart asset template attributes are placeholders to enable the actual references and link tables when the templates are applied to an actual asset. The smart assets are combined to form a base asset hierarchy that can be used to create relative asset hierarchies for context and ease of navigation. Another key capability of smart asset templates is the ability to have base and relative templates with inheritance to allow for the anomalies commonly found in asset classes.

The digital operational infrastructure[a] can enable asset anomaly detection by allowing the SME to create or modify anomaly expressions and then to test the expressions by backcasting (i.e., running the expression back into the operational history). Once satisfied with the expression, the SME can then forward-cast this modified expression or event detection algorithm to other assets that utilize the same digital twin template. This powerful capability enables continuous improvement of calculations, expressions and event analytics over time, as well as comparison of similar expression results, KPIs or events as part of the diagnostic process. **FIG. 7** is an illustration of an asset hierarchy associated with a no-code digital twin.

The no-code digital twin can include operational metadata, engineering data and MMS metadata to create a pump curve and overlay with real-time pump performance (**FIG. 8**). Actual pump performance can be viewed over time to see historical performance and, for future references, be based on other forecasted information. This is also an example of how the output of calculations and expressions can be historized to enable their use in other calculations and analytics.

Consolidating the concepts, capabilities and applications, **FIG. 9** illustrates how smart asset templates are leveraged to create a digital replica of a physical renewable diesel facility and to form the foundation for a portfolio of dashboards, KPIs and advanced decision support capabilities.

A 'layers of analytics' strategy for renewable diesel facilities. Terms such as advanced analytics, machine learning, big data and artificial intelligence (AI) appear pervasively in marketing literature, but can lead to confusion, failed projects and significant lost opportunity costs.

The most successful operators achieve value from analytics by first defining an analytics framework, along with the types of analytics required, and then selecting fit-for-purpose technologies. They use a "layers of analytics" strategy, which considers incremental cost vs. incremental

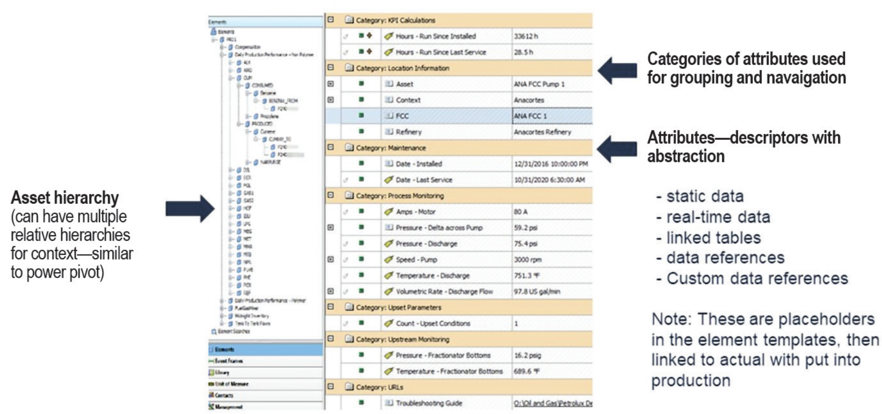

FIG. 7. Operational data management in a no-code operational digital twin.

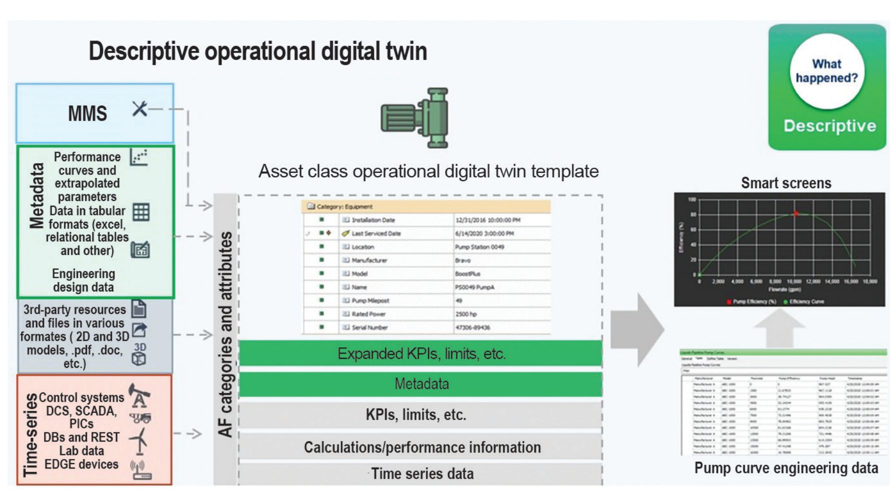

FIG. 8. Example of an operational digital twin and integrated data references used in analytics and visualization.

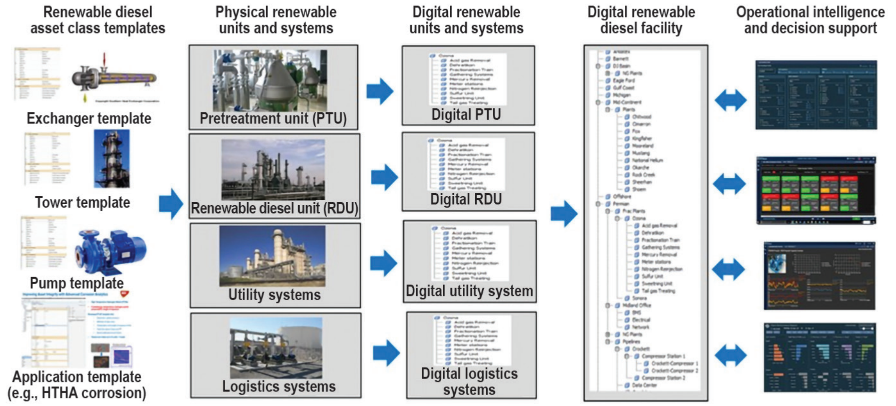

FIG. 9. A smart renewable diesel facility configuration from digital twin asset building blocks.

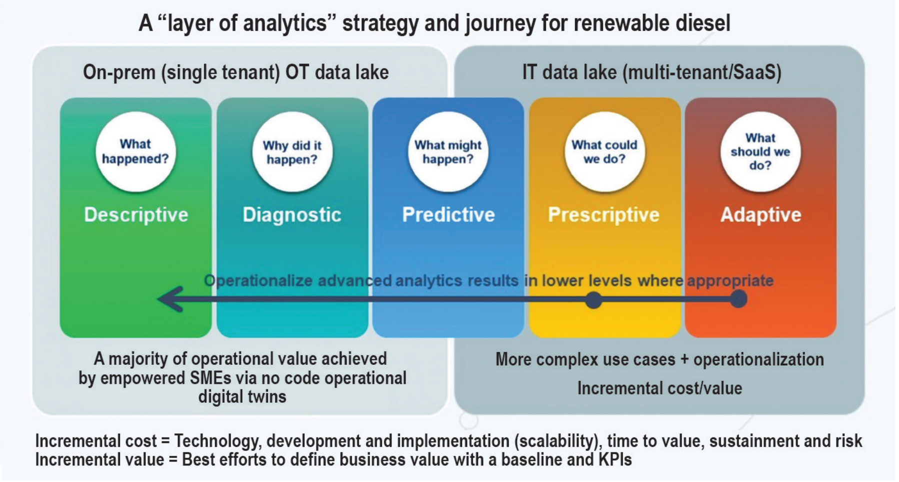

FIG. 10. Using incremental cost/value evolution through layers of analytics and hybrid data lakes.

value as they move to more complex analytical methods. The costs include not only the technology, but also the costs associated with lost time to value, scalability, configuration, sustainment and risk of attainment.

The foundation of this "layers of analytics" approach (**FIG. 10**) relies on the use of an operational data infrastructure[a] to enable SMEs, not IT, to configure real-time descriptive, diagnostic and simple predictive analytics by using formulas, empirical correlations and rule-based expressions. These lower-level analytics form the foundation for more advanced predictive, prescriptive and adaptive analytics that use machine learning and other methods, and require collaborative support from data science teams.

These foundational analytical layers generally provide over 80% of the value for about 20% of the cost vs. more advanced analytical layers that only use technologies such as machine learning.

Once higher layers of analytics are utilized, it is imperative to feed back the results of these advanced layers to the lower-level layers as forecasts or targets, where appropriate, to operationalize the advanced analytical output. This is key to the development of the smart renewable diesel, as results from the integration with process simulation optimization models and financial data for real-time gas plant financial optimization are fed back to the operational data infrastructure.[a]

Takeaway. The growth of renewable diesel, by either building new facilities or modifying existing petroleum refineries, is global, and opportunities are expanding rapidly to address social, regulatory and financial needs and opportunities. Renewable diesel PTUs and RDUs present both operating challenges and opportunities that can successfully be addressed to leverage a proven, powerful and configurable operational data infrastructure[a] used by many HPI companies worldwide. The key is the ability to enable SMEs to configure smart asset digital twins that can be combined to create an operational digital twin of the renewable diesel facility, including associated utility and infrastructure systems.

The operational data infrastructure forms the foundation for real-time operational intelligence and proactive, exception-based decision support. It also enables the use of modern digital technologies, such as analytics, financial base modeling and optimization, and safe and secure ecosystem digital integration.

The result is the ability to increase safety and to mitigate processing challenges in the PTU and RDU, as well as to increase effective capacity by 2%–4% by boosting asset reliability, reduce O&M costs by 3%–5%, and increase EBITDA performance by 3%–5%. HP

NOTES

[a] Refers to OSIsoft's PI System
[b] Refers to PI System's Asset Framework (AF)

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Meeting the Tier 3 challenge with ultra-clean alkylate

The U.S. Environmental Protection Agency (EPA) introduced Tier 3 gasoline sulfur standards in 2017, requiring all U.S. gasoline producers to adhere to an annual 10-ppm average sulfur limit. A 3-yr extension was provided for about 30 small refineries, which expired on January 1, 2020. The program includes a 6-yr provision allowing refineries that cannot produce qualifying gasoline to buy credits from other refineries to comply with the Tier 3 requirement. The credits are generated by refineries producing gasoline with an annual sulfur content below 10 ppm. At the end of October 2019, the price of these credits increased by 250%, indicating that demand for the credits were possibly greater than their supply.

Refiners have a limited number of options to reduce sulfur levels in gasoline to meet the new 10-ppm requirement. For Tier 3, removing the remaining, more difficult sulfur molecules may lead to more significant octane loss. Most refiners are meeting the regulations by increasing hydrotreating severity either with pre-treating fluid catalytic cracking (FCC) feed or post-treating FCC naphtha. This option increases the refinery hydrogen consumption and reduces the run length of these hydrotreaters. While post-treating is effective for reducing the sulfur content, it saturates olefins, resulting in octane loss in the FCC naphtha. This can be exacerbated at refineries that consume an increased diet of shale-derived crudes, which are naturally light and produce low sulfur but also low-octane gasoline. The increasing value of gasoline octane in recent years is illustrated in **FIG. 1.**

Alkylate: The ideal blendstock. Accordingly, alkylate has emerged as a preferred gasoline blending component because it contains no sulfur, no olefins and no benzene, and has a low vapor pressure and a high octane number. U.S. refineries produce 1.3 MMbpd of alkylate, which is produced by reacting isobutane with light olefins, using liquid acids [either hydrofluoric (HF) or sulfuric acid]. The use of these corrosive materials raises maintenance costs. Adding significant costs to the operation are the storage, transport and regeneration of the acid. Solid-acid-catalyzed alkylation eliminates the EHS issues and costs associated with using and regenerating corrosive liquid acids.

A proprietary solid-acid alkylation process. Typical solid-acid catalysts deactivate in minutes. After years of development, a new solid-acid catalyst technology[a] has reached the point of outperforming these liquid acids. The engineered solid-acid catalyst has been designed at multiple levels to provide more than 24-hr cycle times. It also offers robust resistance to typical poisons (such as mercaptans, diolefins and oxygenates), along with the ability to handle a variety of feedstocks. The proprietary catalyst forms the core of a safe and efficient proprietary solid-acid alkylation process[b] that generates high-octane alkylate without the hazards and costs associated with liquid acid technology. Additionally, it features a simple fixed-bed reactor design and regeneration using hydrogen.

The integration of catalyst science and reaction engineering allows the proprietary catalyst cycle times that are an order of magnitude longer than most solid-acid catalysts and produces high-octane alkylate from isobutane and light olefins (ethylene, propylene, butylenes and amylenes) from any source. The stable catalyst performance greatly simplifies the overall process design, which reduces the capital cost of the alkylation plant, while lowering energy consumption. Innovations in the proprietary solid-acid catalyst system are shown in **FIG. 2.**

Catalyst performance with various feedstocks. The proprietary solid-acid catalyst has been tested with various feedstocks and produces alkylate with a high octane rating over a wide range of operating temperatures, olefin space velocities and feed compositions. Results from the bench-scale testing are summarized in **TABLE 1.** The octane values and Reid vapor

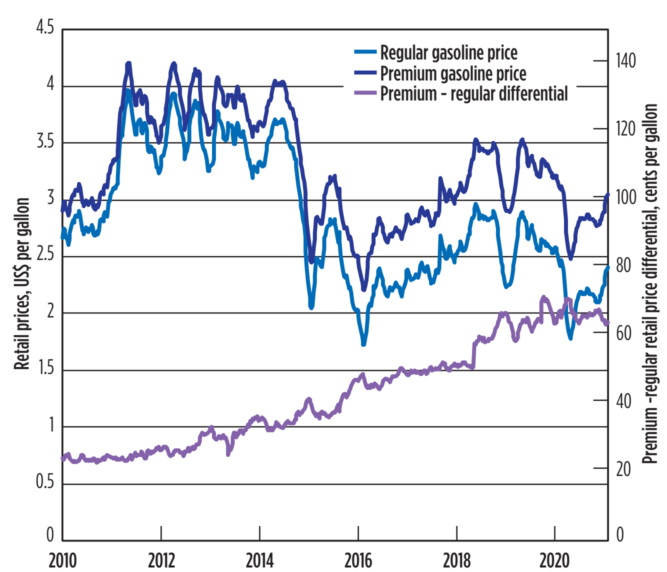

FIG. 1. Gasoline prices and premium-regular retail price differential. Source: U.S. Energy Information Administration (EIA).

pressure (RVP) were computed using the gas chromatography product analysis and confirmed by independent engine testing.

In general, the octane values for alkylate produced by the proprietary catalyst tend to be higher than those obtained by either liquid acids or ionic liquids for three main reasons. Those include:

1. The proprietary catalyst has an inherent functionality that converts n-butenes to a mixture of 1-butene, trans-2-butene and cis-2-butene. As a result, irrespective of the type of normal butene used as feed, the product composition of the alkylate is identical.
2. The trimethyl pentanes-to-dimethyl hexanes (TMP/DMH) ratio for alkylate produced by the proprietary catalyst is roughly double the value for TMP/DMH ratios produced by liquid acids or ionic liquids. The octane values for TMPs range from 100–109, while those for DMH range from 55–75. High TMP/DMH ratios boost the alkylate octane rating.
3. The distribution of TMP molecules produced by the proprietary catalyst is different from those produced via other processes. While the dominant TMP produced by most alkylation processes is 2,2,4-trimethyl pentane, which has a RON of 100, the proprietary catalyst tends to favor 2,3,4-trimethyl pentane and 2,3,3-trimethyl pentane, which have RON ratings of 103 and 106, respectively.

A combination of these three effects boosts the octane rating of alkylate produced by the proprietary catalyst vs. other technologies.

TABLE 1. Proprietary catalyst performance with various refinery feedstocks

	FCC olefins	MTBE raffinate	FCC offgas with ethylene and propylene	Propylene-rich feeds
Research octane number (RON)	97	99	96	95
Motor octane number (MON)	93	95	93	92
RVP, psi	3.3	2.8	4.1	3.8
Yield, vol/vol olefin	1.88	1.86	1.85	1.85

TABLE 2. Typical contaminants in alkylation feedstock

Contaminant	FCC olefins	MTBE raffinate
Water, ppm wt	300	300
Mercaptans, ppm wt	25–100	25–100
Hydrogen sulfide, ppm wt	< 1	< 1
Butadiene, wt%	0.4–1	0.4–1
Dimethyl ether, ppm wt	–	500
MTBE, ppm wt	–	25
Tert-butyl alcohol, ppm wt	–	5
Methanol, ppm wt	–	25

TABLE 3. Effect of feed contaminants on alkylate quality

	Base Case feed	High-oxygenate feed	High-sulfur feed	High-diene feed
Olefin composition, wt%				
Propylene	49	49	49	49
Butenes	49	49	49	49
Amylenes	2	2	2	2
Contaminants, wt ppm				
Oxygenates	33	210	35	35
Mercaptans	22	25	220	22
Dienes	903	910	910	2,120
Alkylate properties				
RON	95	95	95	95
MON	91	91	91	91

Feed contaminants. Poisoning is the strong chemisorption of reactants, products or impurities on acid sites otherwise available for catalysis. Certain feed contaminants act as catalyst poisons and increase the rate of deactivation of the catalyst. Typical feed impurities for alkylation units are shown in **TABLE 2.**

These feed impurities lead to an increase in liquid acid consumption for sulfuric and HF acid alkylation technologies. In general, the recommended limits for feed contaminants using these liquid acids are less than 10 ppm each for sulfur, dienes and oxygenates. For solid-acid catalysts, the feed contaminant

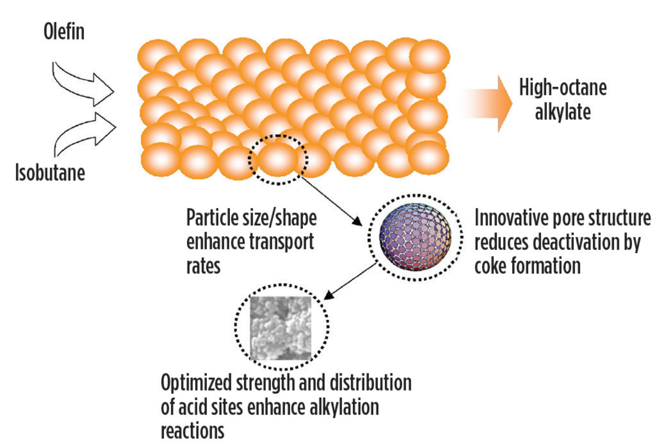

FIG. 2. Innovations in the proprietary solid-acid catalyst system.

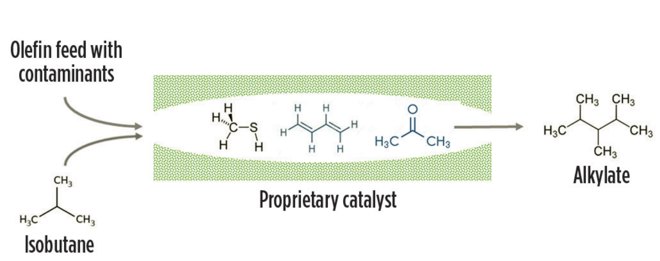

FIG. 3. The proprietary catalyst[a] can trap most feed contaminants (e.g., mercaptans, dienes and oxygenates), while allowing high-octane alkylate molecules to diffuse out easily.

acts as a temporary poison by occupying an acid site, which then becomes unavailable for alkylation.

However, the proprietary catalyst—which is zeolitic in nature—can remove these contaminants without the need for extensive pretreatment. These contaminants—which remain adsorbed on the catalyst surface—are removed during the regular regeneration procedure, allowing the catalyst to recover its full activity. This unique feature has important consequences for Tier 3 regulations. Even though the olefinic feedstocks may contain sulfur or oxygenates, the alkylate produced is essentially sulfur and oxygenate free (**FIG. 3**).

Performance with feed contaminants. Equally important is the quality of alkylate produced for feedstocks containing high levels of contaminants. There is no change in the quality of alkylate produced for feedstocks with high levels of contaminants for a mixed C_3 and C_4 olefin feed (**TABLE 3**).

Proprietary solid-acid alkylation process[b] design. A unit process diagram of the proprietary process is shown in **FIG. 4.** In the reaction zone, isobutane and olefins are reacted to produce alkylate. The reaction takes place over the solid-acid catalyst in fixed-bed reactors. Three fixed-bed reactors with recirculation are used in the reaction section. Two are used for alkylation, while the other is being regenerated in a staggered cycle. The reactors typically contain multiple beds, with olefin feed spargers between each bed. A portion of the olefin feed and the reactor recirculation stream are combined and introduced at the top of the reactor.

The alkylation reaction is mildly exothermic. The reaction's heat is removed by a heat exchanger located in the recirculation loop outside the reactor. As in conventional alkylation units, the reactor effluent is sent to a distillation train consisting of two columns. First, a deisobutanizer is used to recover excess isobutane, which is returned to the reactor. Excess n-butane is removed from the alkylate product in this column, as well. Second, a depropanizer is used to remove light components—mainly propane—from the system. The proprietary process does not require any neutralization or washing equipment to post-treat the alkylate product.

At the end of the 24-hr alkylation cycle, the feeds are switched to the newly regenerated reactor, and the catalyst in the previous (i.e., in-service) reactor is regenerated. A vapor-phase circulating loop containing hydrogen and light hydrocarbons is used to heat the reactor to about 275°C (527°F), at which point catalyst regeneration occurs. Due to the small amount of soft-coke buildup during the reaction cycle, hydrogen consumption is low. After 2 hr at this condition, the loop is used to cool the reactor to the reaction temperature. Fresh isobutane is charged to the reactor, making the reactor ready for the next alkylation cycle. This sequence is controlled by a programmable logic controller.

Techno-economic analysis. Due to lower capital costs and a higher alkylate margin, the proprietary solid-acid alkylation

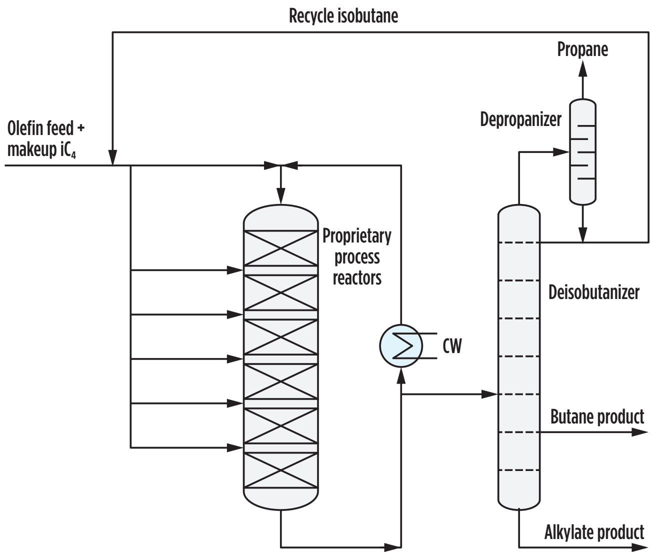

FIG. 4. Proprietary solid-acid alkylation process unit diagram.

FIG. 5. View of a commercial solid-acid alkylation[b] unit.

process offers significantly higher return on investment vs. liquid catalyzed alkylation units.

The capital cost savings result from multiple sources. First is the elimination of corrosive acid from the process. Removing the liquid acid eliminates the acid neutralization equipment, product washing vessels and storage tanks for fresh and spent acid. Second is the change in process conditions. The solid-acid catalyst operates optimally at around 50°C (122°F). Sulfuric acid and ionic liquid alkylation units require refrigeration to generate reasonable alkylate octane, operating around 5°C (41°F), which requires expensive compressors and refrigeration loops. Eliminating refrigeration also leads to a considerable reduction in power costs. A summary of the utility requirements is provided in **TABLE 4.**

Differences in catalyst regeneration procedures also lead to considerable savings, which may be considered either capital or operating costs. The solid-acid catalyst is regenerated in the reactor with hydrogen, generating only a small purge of hydrogen and light hydrocarbons. Sulfuric acid requires a large regeneration plant that is either operated onsite (large capital cost) or by another party (large operating cost).

TABLE 4. Typical utility requirements

	Solid acid	HF acid	Sulfuric acid	Ionic liquid
Utility consumption, standard oil basis and EO/t alkylate	92.3	92.5	103.1	133.81

Liquid-acid alkylation and spent-acid recovery units generally incur high maintenance costs due to the presence of corrosive acid. In numerous refineries, the turnaround and inspection intervals of the alkylation unit are determined by the well-documented challenges associated with acid corrosion. A solid-acid catalyst eliminates these challenges and allows the turnaround interval to be extended to come in line with the upstream FCCU. The maintenance and inspection activities during operation and turnaround periods are also simplified without the presence of liquid acids, thus increasing productivity.

The proprietary solid-acid catalyst outperforms liquid catalyst processes in both alkylate yield and octane, thereby boosting alkylate margins from the available olefin feedstock. Alkylate octane using the proprietary catalyst is typically at least one point higher than any other technology. Alkylate yields are around 5% higher than liquid acid processes.

Performance of a commercial solid-acid alkylation unit. A commercial solid-acid alkylation[b] unit has been in operation in Shandong Province, China, for more than 2 yr, meeting and exceeding predicted product quality parameters. The unit has demonstrated consistent performance and alkylate quality through more than 300 regeneration cycles per reactor, proving the robustness of the proprietary catalyst. **FIG. 5** shows a view of the plant.

Two additional proprietary solid-acid alkylation projects are underway in North America. The first project is related to the revamp of an HF acid alkylation unit, and the second is to revamp a sulfuric acid alkylation unit. HP

NOTES

[a] Exelus' Solid-Acid Catalyst (ExSact) technology
[b] KBR's K-SAAT™ technology

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A solution to the IMO 2020 MARPOL Annex VI requirement

On January 1, 2020, a new requirement limiting the sulfur content of marine fuel to a maximum of 0.5 wt% went into effect. The International Maritime Organization's (IMO's) 2020 MARPOL Annex VI rule globally prohibits ships from operating while using a fuel with more than 0.5 wt% sulfur without an exhaust gas scrubber.

Most ship engines in service were designed to operate with ISO 8217-compliant high-sulfur, heavy residual fuel oil. Historically, ISO 8217-compliant fuel oil is generated by combining various high-sulfur refinery residues with varying percentages of cutters, vacuum gasoil (VGO) and gasoil until the fuel specification is met.

From the perspective of marine engine design firms and shipowners, the most desirable way to comply with the new regulation would be to use a heavy residual fuel oil that meets the ISO 8217 fuel specification and has a sulfur content of less than 0.5 wt% sulfur. An early recognition for such a fuel oil led to the development of a proprietary upgrading process[a] several years before the IMO 2020 rule took effect. Since the patented very-low-sulfur fuel oil[b] (VLSFO[b]), which was made using this proprietary process, maintains ISO 8217 bulk properties, it reduces the risk of engine performance problems related to fuel oil blending.

Due to the COVID-19 pandemic, the decline in demand of transportation fuel resulted in an excess of distillate materials—and in the refinery streams used to produce those same distillate materials. The excess of distillate and intermediate refinery products drove the industry toward blending distillate fuel oils or blending distillate materials with residual materials to adhere to the IMO marine fuels regulation. A wide range of problems related to such VLSFO blends available in the market are being reported in literature.[1,2,3] From sludge formation, engine damage, safety concerns and pollution to increased soot and dumping of sludge, the new VLSFO formulations are creating significant safety and performance concerns for the shipping industry. Distillate blends may cause wear and tear to ships' engine systems, as their bulk properties can be adversely affected when distillates are mixed with residual materials. Because the proprietary VLSFO is created solely through hydroprocessing, the resultant product is compliant and homogenous.

While installation of scrubbers on ships is an alternative to using VLSFO, scrubbers present significant issues, including complex operation, costly maintenance, emissions violations, bans on open-loop scrubbers in some ports, and disposal issues for toxic byproducts and sludge.[4,5,6,7,8,9]

The patented upgrading process. Refining processes have historically focused on breaking down and upgrading residual material to create higher-value distillate products. Counter to traditional residue upgrading technologies, the proprietary upgrading process intentionally maintains the bulk properties of residual fuel that make it the preferred fuel of the shipping industry. The patented technology is rooted in commercially proven refining processes, utilizing an alternate approach counter to traditional refinery residual material upgrading processes such as hydrocracking, deasphalting and coking. Because the proprietary upgrading process does not focus on cracking, hydrogen consumption is significantly lower than hydrocracking, and no low-value residual products remain to be processed further or sold into the high-sulfur fuel oil (HSFO) market.

The proprietary upgrading process was designed with a focus on three primary principles. These include:

1. Feeding the process an ISO 8217-compliant heavy marine HSFO and removing the sulfur and other environmental contaminants, while maintaining the energy density and other bulk properties of residual fuel oils for which most ships' main engines are designed.
2. Addressing the overabundance of HSFO and high-sulfur residual components in the market by developing a straightforward, robust process to produce 0.5 wt% sulfur ISO 8217 residual fuel oil with a minimal yield of byproducts. Using 1 mass unit of HSFO feed, the proprietary upgrading process produces approximately 0.96 mass units of ISO 8217-compliant VLSFO, with the balance being about 0.025 mass units of sulfur and minor amounts of wild naphtha and light ends (less than 0.015 mass units).
3. Positioning the process to be installed on a compact footprint within a refinery or near/adjacent to points of aggregation (i.e., fuel oil terminals). A preferred location will have excess hydrogen or pipeline hydrogen available and will utilize existing systems (e.g., tanks and utilities) of the current logistics flow in the existing HSFO supply chain. The addition of the proprietary upgrading process unit should

cause little or no disruption to existing refinery infrastructure.

Commercially, the proprietary upgrading process is a lower-priced alternative to hydrocracking. Capital costs for estimated inside battery limits for implementation of an ebullated-bed hydrocracker are more than three times higher than the capital costs for implementation of the proprietary upgrading process unit of the same capacity. Outside battery limit integration costs are also significantly lower for a proprietary upgrading process unit. On a per-barrel operating cost basis, the proprietary upgrading process unit is about one-fourth the operating costs of an ebullated-bed hydrocracker. The proprietary upgrading process is much less operationally complex and is safer than residue upgrading alternatives.

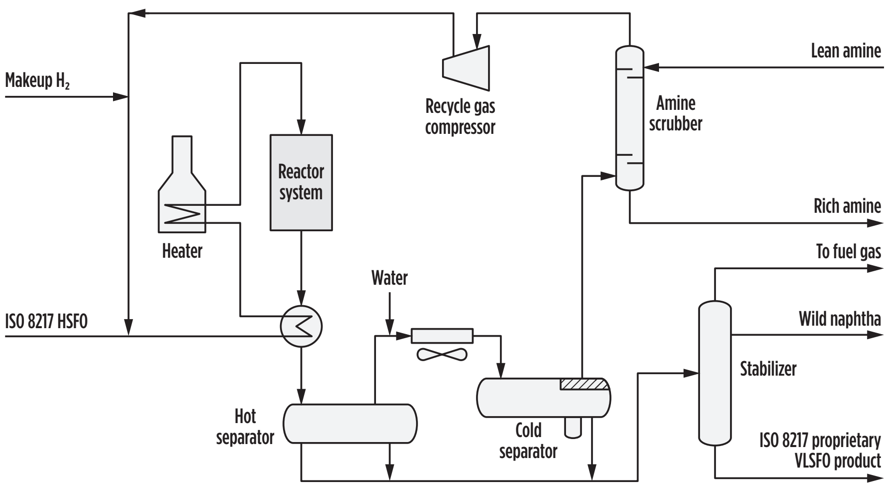

FIG. 1. Process flow diagram of the proprietary upgrading process.

In addition to the benefits outlined, a modular proprietary upgrading process unit allows much faster entry into the market, with the lowest need for integration and disruption to existing infrastructure at either a refinery or marine terminal. A modular version of the proprietary upgrading process can be fully operational at a greenfield site in less than 2 yr from the date of placing an order—or even sooner, if located inside an existing refinery, which is half of the schedule for a comparable ebullated-bed hydrocracker or coker. Beyond price and speed-to-market considerations, both coking and hydrocracking produce some amount of low-value residual material that must be sold into the market at a value lower than the feedstock and

TABLE 1. Comparison of the proprietary fuel

	RMG 380 ISO 8217 specification	RMG 380*	Marine gasoil	80/20 blend to 0.5% sulfur**	Proprietary VLSFO[b]
Yield					
Density at 15°C (59°F)	991 max.	990.3	870.1	891.7	950.2
Metric tons (t)		1	1	1	1
Barrels at 15°C (59°F)		6.36	7.24	7.07	6.63
Volume in m^3 at 15°C (59°F)		1.01	1.15	1.12	1.05
Specific energy					
Sulfur content, % m/m	0.5 max.	2.5	< 0.1	0.5	0.45
Ash content, % m/m		0.09	< 0.01	0.03	< 0.01
Gross specific energy, Btu/gal		152,000	142,000	144,000	150,000
Net specific energy, Btu/gal		143,000	133,000	135,000	142,000
Calculated carbon aromaticity index (CCAI)	870	852	–	831	824
Cetane index	–	–	40	–	–
Carbon and metals					
Carbon residue, wt%	18 max.	12.18	0	2.6	6.59
Aluminum and silicon, mg/kg	60 max.	52	0	10	< 1
Vanadium, mg/kg	35 max.	151	0	30	20
Sodium, mg/kg	100 max.	40	0	8	< 1
Acid number, mg KOG/g	2.5 max.	0.53	0.15	0.23	< 0.05
Kinematic viscosity at 50°C	380 max.	369.7	2.5	4.4	120
Pour point, °C	30 max.	–12	–2	–4	–18
Flash point, °C	60 min.	101	66	68.7	110

* RMG 380 is a blend of refinery streams. It is now salable as HSFO.
** Blend of RMG 380 and sufficient gasoil to meet the 0.5% sulfur requirement

generally lower than HSFO. Compared to available information on competitive technologies, the proprietary upgrading process is the fastest to market—as either a fully modular or stick-built unit—because it has a lower capital expenditure and operational expenditure and is rooted in process technologies broadly understood and accepted by refiners.

As shown in **FIG. 1,** feeding the proprietary upgrading process is ISO 8217-compliant HSFO, which is mixed with hydrogen and heated against the reactor effluent. It is then heated to the reactor inlet temperature in a furnace and fed to the reactor system. The reactor system utilizes commercially available hydrotreating catalysts in its design. Effluent from the reactor system flows through the feed/effluent exchanger and to a series of vessels to separate liquid product from recycled vapor. Recycled hydrogen is contacted against amine to remove hydrogen sulfide (H_2S) and is recycled to the reactor system via a recycle hydrogen compressor. Liquid effluents from the separator drums feed the product stabilizer. Hydrogen, H_2S and light components are stripped from the liquid effluents to produce ISO 8217-compliant VLSFO or ultra-low-sulfur fuel oil (ULSFO).

The proprietary upgrading process was successfully piloted at two separate pilot plant facilities, using three different commercial marine fuel oils (not laboratory blends): two RMG-380 feeds with 2.5 wt% and 2.9 wt% sulfur, and an RMK-500 feed with 3.3 wt% sulfur, to produce an ISO 8217-compliant VLSFO with 0.5 wt% sulfur. Production of an ULSFO with 0.1 wt% sulfur, which is a compliant fuel for MARPOL Annex VI designated emissions control areas, was also demonstrated during the pilot testing.

Proprietary fuel[b] properties. The proprietary fuel has been well received by the shipping industry and engine manufacturers, as it maintains energy density and remains compliant on all ISO 8217 specifications. As shown in **TABLE 1,** the ISO 8217 properties of the RMG-380 HSFO (i.e., the feed to the proprietary upgrading process) are compared to those of the proprietary VLSFO and to the two other widely available alternative bunker fuels used for compliance with IMO 2020 requirements: a marine gasoil and a blended VLSFO (80:20 blend). Of the three IMO 2020-compliant fuels, the properties of the proprietary fuel most closely align with HSFO, the fuel for which most ship engines were designed to use. In addition to producing an ISO 8217-compliant fuel with lower sulfur content, metals, catalyst fines and other environmental contaminants are nearly completely removed by the proprietary upgrading process. Metals reduction of 80%–90% is achieved in the proprietary upgrading process, and catalyst fines (aluminum and silicon) are reduced by more than 90%.

Compatibility and miscibility. The author's position is that blending HSFO with distillates is not a commercially acceptable and sustainable solution to the IMO 2020 regulatory requirements. In the short term, blending a VLSFO requires the use of higher-value (and there-

by higher-cost) ultra-low-sulfur distillates that are only more readily available during 2020–2021 due to decreased demand for transportation fuels because of the global pandemic. However, the asphaltenes present in residual streams are often not compatible with paraffinic distillates, which may cause serious problems.

Commercial experience, and several prior and recent industry surveys, show that blending to produce a low-sulfur fuel oil can result in a fuel that is incompatible with ship engines.[10] In addition, blends "loaded on top" of residual fuels, distillate fuels or other blends in storage tanks or on ships can cause precipitation of asphaltenes due to incompatibility of these blends with other fuels. With these unstable blends, precipitated asphaltenes form sludge in tanks that can plug filters, purifiers, fuel injection equipment and even fuel lines. Precipitated asphaltenes cannot be brought back into solution, meaning that this sludge formed by a blended VLSFO will also need to be cleaned from tanks and fuel systems before being safely disposed of on land.

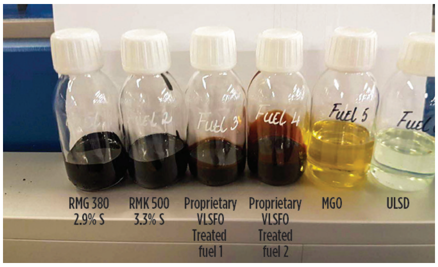

FIG. 2. Fuels for compatibility testing.

The author's company has carried out compatibility and miscibility tests to demonstrate that the proprietary fuel does not create or experience these issues. The proprietary VLSFO was tested with RMG, RMK and distillate grades of marine fuels, and has proven to be miscible with residual fuels, as well as MGO and ultra-low-sulfur diesel (ULSD) in mixtures of 50/50, 30/70, 20/80, 10/90 and 5/95. Compatibility test samples and results are shown in **FIGS. 2** and **3.**

Shelf life. Shelf life refers to the length of time that fuel oil remains stable and in solution in storage. The reserve stability number (RSN)—as measured by ASTM D7061—is an industry-accepted measurement of the stability of marine fuels. Fuels with an RSN of less than 5 are considered to pass and have a high stability reserve. Asphaltenes are not likely to flocculate, and the fuel is stable with a commercially reasonable shelf life. Fuels with an RSN of 5–10 have a much lower stability reserve, with limited shelf life and may flocculate. Fuels with an RSN greater than 15 are considered unstable. Testing has shown that, after more than a year in storage, the proprietary VLSFO had an RSN of 1.2—thereby demonstrating that the proprietary fuel is stable and has no issues around shelf life. Blends and other VLSFO/ULSFO products on the market are reported to have shelf-life problems and may be stable for just a matter of days or weeks in storage. This can create major issues with sludge formation over time in storage tanks on land and onboard ships. Costly and time-consuming cleaning of tanks and maintenance of ship fuel systems are required when unstable fuels have been bunkered.

Ignition and combustion properties. Ignition delay is the time that elapses from the start of fuel injection to the point of combustion. A long ignition delay results in an accumulation of unburned fuel in the combustion chamber, which can cause knocking, poor engine performance and, eventually, engine damage. The proprietary fuel demonstrated superior ignition properties when tested using the combustion pressure trace test.

FIG. 4 illustrates the proprietary fuel's combustion and ignition properties vs. "normal" fuel (ECN=29) and a "problem" fuel (ECN=8), as taken from the International Council on Combustion Engines' (CIMAC's) 2011 "Fuel Quality Guide–Ignition and Combustion."

Poor combustion performance is normally characterized by an extended combustion period, along with low rates of pressure increase and low maximum pressure, resulting in incomplete fuel combustion. In contrast, good combustion exhibits a minimal ignition delay, a rapid combustion period, and high rates of pressure increase and high maximum pressure. The proprietary fuel possesses superior combustion performance, as demonstrated by the rate of heat release (ROHR) curve in **FIG. 4.**

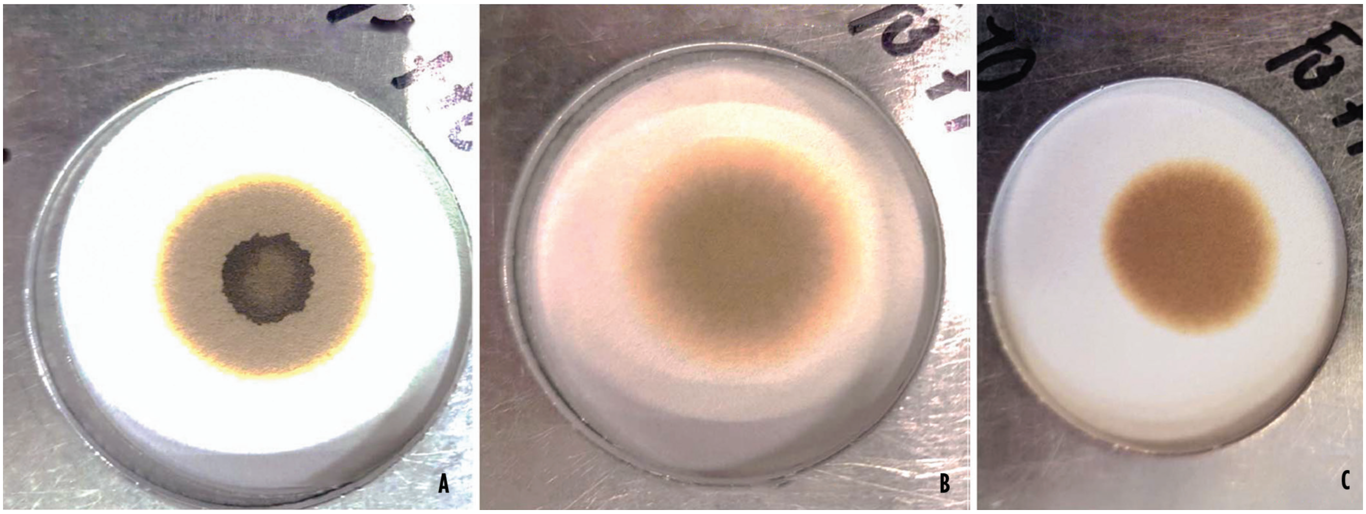

FIG. 3. Fuels for miscibility testing: (A) 20% RMG 380/80% distillate, (B) 20% proprietary fuel/80% distillate, and (C) 30% proprietary fuel/70% distillate.

Lubricity. Lubricity is commonly defined as the ability of a fluid to minimize friction between surfaces in relative motion under load conditions. A fuel oil with poor lubricity can rapidly cause severe wear to liners and piston rings, create turbocharger issues and ultimately result in engine failure. The ISO 12156 test method is commonly used to determine the lubricity of marine fuels. When tested in accordance with ISO 12156, the proprietary fuel resulted in lubricity of less than 100 µm, showing its superior lubricity properties vs. distillate-based fuels. For purposes of comparison, the lubricity specification for distillate fuels is less than 520 µm, meaning that anything less than 520 µm meets the requirement for lubricity.

Another issue related to lubricity recently identified and associated with low-sulfur fuel oil blends is FCC catalyst fines, which are present in small quantities. The catalyst fines, which are present in HSFO base material, become abrasive when blended with low-viscosity, ultra-low-sulfur distillates and can cause significant cylinder wear in ships' engines. Because

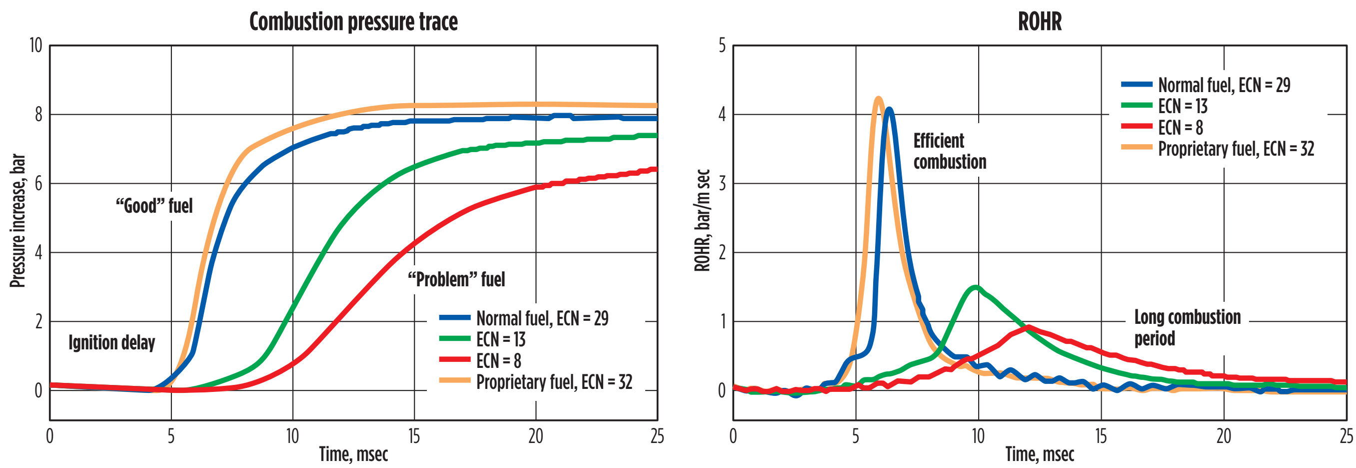

FIG. 4. The proprietary fuel has ignition and combustion properties superior to a CIMAC good fuel (green line) based on the IP 541/06 fuel ignition and combustion test.

the proprietary VLSFO exceeds the lubricity specification and does not contain abrasive catalyst fines, these are not a concern for ships using the proprietary fuel.

Takeaway. The proprietary fuel meets the ISO 8217 specification for the residual marine fuel oil preferred by the shipping industry and is a robust solution to the environmental regulations specified in IMO 2020 MARPOL Annex VI, thus producing significantly lower sulfur oxide and nitrogen oxide emissions than HSFO. The proprietary upgrading process is rooted in commercially proven hydroprocessing technology—removing sulfur, metals and other contaminants from ISO 8217 high-sulfur residual marine fuel oil. With its lower hydrogen consumption and energy demand, the proprietary process has a smaller greenhouse gas impact than other residue upgrading options. HP

NOTES

[a] The Rigby Process®
[b] Rigby Fuel (VLSFO)

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Renewable diesel: The latest buzzword in the downstream sector

Renewable diesel: this greener, cleaner fuel has taken our industry by storm. However, those who have operated in the refinery space over the last decade know that this will not be the last innovation to rock our world. The industry continues to adjust to meet market needs and leverage new process innovations. So, what is so unique about this fuel, and why does the world need it now?

It is not enough to be economic—it must be green. Our industry is changing and evolving. Many shareholders of major oil and gas companies want to see companies investing in cleaner and greener ways to produce energy, but these projects must make economic sense.

In the U.S., California's LCFS (Low-Carbon Fuel Standard) gives refiners economic credit for producing low-carbon fuels. The standard is designed to decrease the net carbon intensity of the transportation fuel pool and to provide a range of low-carbon and renewable alternatives that reduce petroleum dependency and achieve air quality benefits.[1] California has been the most aggressive state in this regard. With a stated goal of replacing petroleum diesel with renewable diesel by 2030, California gives refineries and energy producers tax credits for producing renewable products. Other states such as Oregon and Washington have followed suit and several more states are predicted to adopt a similar standard.

What does this mean for refineries? It is no secret that the refining industry has been heavily impacted by the shifting domestic fuels market. Demand growth for certain refined products was slow before the shutdowns associated with the COVID-19 pandemic. Smaller refineries have particularly struggled with the recent collapse in oil prices, shrinking growth and margins for gasoline and other refined products, and the discontinuation of waivers for renewable identification numbers (RINs) credit exceptions. We expect to see that approximately 1 MMbpd of refining capacity in North America will be gone permanently. Some of the capacity will be refurbished by using hydrocarbon plants to run renewable feedstock, such as vegetable oils, animal fat and used cooking oil, with an added bonus to open access to government credits by making renewable fuels.

A renewable diesel unit addition could provide just the boost needed for a refinery that has suffered in this volatile market. Many refineries are investigating spending their CAPEX budgets on renewable diesel and related projects. These projects can be in the form of a grassroot renewable facility, the revamp of an existing unit, or adjusting an existing plant to co-process both petroleum and renewable fuels.

What is the market for renewable diesel? With only five renewable diesel plants now in operation in the U.S., the market is primed with opportunity for RDU production. According to the U.S. Department of Energy, these five plants have a combined capacity of nearly 400 MMgpy. Production is expected to grow in the coming years due to expansions at existing plants and the construction of new plants.

While the U.S. Energy Information Administration (EIA) does not report renewable diesel production, the U.S. Environmental Protection Agency (EPA) reports Renewable Fuel Standard (RFS) RIN data, which indicates that the U.S. consumed more than 900 MMgal in 2019. Nearly all domestically produced and imported renewable diesel is used in California due to economic benefits under the Low-Carbon Fuel Standard[2]; with states like Oregon, Washington, New York and even Canada following suit, now is the ideal time to adjust operations to follow the market need for renewable diesel. By 2025, Platts Analytics predicts that the total renewable diesel supply will reach 5 Bgal; however, demand is expected to be less than one third of the supply. As more renewable diesel plants come online in 2022 and beyond, this can overwhelm the demand and create a surplus of renewable fuels. Time is of the essence for the renewable projects.

What is the difference between renewable diesel and biodiesel? Renewable diesel is defined as diesel that meets all specifications of typical petroleum diesel but is produced by hydrotreating non-petroleum materials, such as vegetable oils, animal fats or biomass. Renewable diesel is completely interchangeable with petroleum diesel and is completely compatible on a 100% basis in existing diesel engines.

Renewable diesel is different than "biodiesel." Biodiesel is produced from many of the same animal and vegetable oils as renewable diesel, but by a different process called trans-esterification. This process adds oxygen to these oils, and when blended with petroleum diesel improves its emissions characteristics. It has certain properties that make it inconvenient to store and limits its content in diesel fuels to 5%–20% due to its incompatibility with existing diesel engines. Due to these disadvantages, its production in the U.S. has been limited.

Renewable diesel produced from vegetable oil, used cooking oil, distillers corn oil or tallow are generally more chemically homogeneous than petroleum diesel. Moreover, renewable diesel has a higher cetane number than petroleum diesel. This number is a measure of how efficiently a diesel engine can generate power with that fuel. As a result, more energy is derived from less fuel, reducing emissions per unit amount of energy. In addition, renewable diesel has essentially zero sulfur and other impurities found in petroleum diesel.

Renewable diesel is considered "low carbon" because the feedstocks used to make renewable diesel, such as distillers corn oil, tallow and used cooking oil, are byproducts from other processes. As such, renewable diesel produced from these feedstocks has a low-carbon intensity. Carbon intensity (CI) is a measure of lifecycle emissions from extraction or growth, refinement, distribution, storage and combustion, and is reported as grams of carbon dioxide (CO_2) equivalent per megajoule (MJ) of energy. Renewable diesel made from the above byproduct feedstocks can be in the range of 22 gCO_2/MJ–25 gCO_2/MJ depending on the specific byproduct feedstock.[2,3] By comparison, petroleum diesel has a CI of 102. Renewable diesel produced from soybean oil, for example, has a CI of 53, as the CO_2 emitted from growing soybeans must be included in the CI calculation.

What does the renewable diesel process look like? In a conventional petroleum refinery, certain crude fractions are hydrotreated to remove sulfur species so the diesel fuel will meet the specifications for ultra-low sulfur diesel (ULSD). The diesel fuel produced by the renewable diesel process is identical to the ULSD produced in a conventional petroleum refinery. However, the process used to produce renewable diesel has some differences from the conventional refinery hydrotreating process.

Renewable diesel is made from non-petroleum renewable feedstocks, such as vegetable oils and animal fats. The glycerides in these feedstocks are converted to straight-chain hydrocarbons by reactions with hydrogen over a fixed catalyst bed. This is followed by an isomerization reaction to improve the cold flow properties of the diesel fuel product. The amount of hydrogen required to produce renewable diesel from tallow, corn oil, used cooking oil and vegetable oils is greater than the typical petroleum refinery hydrotreater.

Therefore, a renewable diesel project often includes additional hydrogen capacity. This leads us to expect a boost in

FIG. 1. A site in Artesia, New Mexico where a grassroots RDU is planned.

hydrogen production in upcoming years as more renewable diesel plants are built.

What is involved in a renewable diesel project? A renewable diesel project involves more than the renewable diesel process unit. In addition to the RDU, the overall project must consider infrastructure such as the logistics of feedstock supplies and diesel product distribution, feed pretreatment, hydrogen supply and utilities. **FIG. 1** shows a facility in Artesia, New Mexico, where a grassroots RDU is planned.

In the case of a refinery conversion, the existing petroleum refinery will likely have significant infrastructure available, such as rail access, truck loading and unloading, as well as existing tankage and utilities. The existing facilities may require some modifications to accommodate some of the feedstocks. For example, animal fats such as tallow will require tank heating, as tallow will solidify at ambient temperatures. An existing refinery will have existing utility systems available such as steam, cooling water, electric power, flare, wastewater treatment and instrument air.

A project planned for a greenfield site must plan for the logistics of feedstocks and products, tankage and the utilities required for the overall project.

Renewable diesel feedstocks will likely require pretreatment before being charged to the RDU. The various pretreatment steps will vary depending on the specific application and the planned RDU feedstocks. As noted earlier, renewable diesel can be produced from a variety of feedstocks: vegetable oils, used cooking oil, distillers corn oil, animal fats, etc. The specific feedstocks planned for the RDU will determine the required pretreatments steps, which may include polyethylene removal, degumming and bleaching to remove metals, chlorides, phosphates and other contaminants that are deleterious to the hydroprocessing catalysts.

In addition to logistics, utilities and pretreatment, an RDU project requires hydrogen. An RDU generally requires more hydrogen supply than a traditional refinery hydrotreater designed to remove sulfur species from petroleum diesel. The hydrogen required will vary depending on the specific feedstock and increase over the run length of the RDU catalyst. An existing refinery will most likely have a source of hydrogen. The hydrogen may be from an industrial gas supplier of a refinery-owned hydrogen production unit. A greenfield RDU project will need to include a source of hydrogen.

Getting started. These basic steps can help owner-operators get started:

1. **Begin with a study:** Conducting a feasibility study identifies the opportunity before beginning the project.
2. **Lay out the plan:** Whether a unit needs to be repurposed to process a variety of renewable feedstocks or the entire refinery needs to be overhauled, engineering and technology will be of the utmost importance to ensure the project is completed safely, efficiently and cost-effectively. Partnering with the right EPC company will bring relevant experience to these types of projects.
3. **Build into reality:** If a grassroot approach is chosen or the plant needs to be revamped as an RDU, milestones and associated costs must be managed to ensure deadlines are met at competitive prices that keep the bottom line intact. HP

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Modular construction: Always considered, now COVID-necessary

The COVID-19 pandemic created a sequence of changes across all industries, and the chemical sector has not been immune to the impact of this global health crisis. What used to be a "nice to have" feature in project execution has evolved into a "must-have" component. Although modular construction is not a new concept, it may become a necessity in current times.

Modularization is described as the process of shifting as much labor-intensive field construction activities from the field to an offsite fabrication facility to mitigate or reduce inherent risks associated with field construction.

Typically, a modular system includes complete process units that are fabricated remotely from the project's destination plant site. The systems are built in a controlled indoor environment, assembly-line fashion horizontally as opposed to vertically, which helps minimize the amount of work and resources needed vs. field construction. The systems include all necessary components and equipment that are placed within a structural steel frame required to deliver a complete process system. These frames serve as support during shipment and provide access to the equipment for operation and maintenance after installation at the plant site.

The project's process design, specifications, engineering standards and guidelines are all taken into consideration and followed to ensure that the executed project meets all expectations and requirements.

Key advantages of modular construction. Considering the importance of operator safety and social distancing during COVID-19, the following are five key advantages of modular construction:

1. **Reduced risk of community spread.** When dealing with on-site construction, depending on the project size, fabrication may require over 1,000 craft workers to be performing different tasks simultaneously. In many cases, these are transient workers who will be newcomers to the community. Adding more people to an area can increase the risk of human-human exposure or could promote the spread of COVID-19 to other areas as the transient workers return home due to crew rotations.
2. **Reduced risk of exposure to the labor force.** Modular assembly typically follows a preset sequence of activities that inherently require a smaller local workforce. This allows for social distancing during work activities, while still being able to adhere to Occupational Safety and Health Administration's (OSHA's) recommended guidelines related to the prevention of workplace exposures to COVID-19. It also brings an advantage from the logistics perspective, as a small local workforce is easier to manage vs. a field-built project, while reducing the likelihood of exposure.
3. **Reduced cost and schedule risk.** Traditionally, customers could see a 25%–30% cost reduction with modular construction when compared to field construction. The project can be quoted as a firm lump sum bid vs. time and materials (T&M) and fabricated to within 90% completion, with items such as piping components, field instrumentation, lighting, electrical wiring and others installed within a steel frame. All of this is done offsite, reducing the amount of onsite work required during installation. Furthermore, in parallel, the customer can proceed to apply for work permits as the construction of the modules have already begun at an offsite shop, while minimizing plant-site interruptions due to construction.

   During a COVID-19 environment, with fabrication occurring offsite, the ability to continue module fabrication when field construction sites would otherwise be shut down or materially impacted by COVID-19, reduces the potential for extended schedule and increased costs associated with delays. Furthermore, minimal plant site interruptions allow the customer to proceed with their normal operations, adjust to the new requirements and create a set of preventive procedures that can be later shared with the module installation workforce.
4. **Increased productivity.** Building a full system in a controlled environment brings many benefits, including increased productivity. For example, the workforce is not subject to weather-related delays and benefit from inherent efficiencies when working in a purpose-built fabrication facility. Considering COVID-19, fabrication shops are not experiencing the same level of productivity hits being taken in the field during construction. In the field, construction teams are implementing preventative measures such as daily pre-work health checks, staggered lunch schedules, breaks and re-checks when the

workforce members enter and exit the field construction facility to minimize risk exposure to COVID-19. These required, and necessary practices are important to protect workers from exposure. However, they come at a cost to productivity. Naturally, a smaller fabrication shop crew vs. a full field construction crew—that could be thousands of workers—minimizes the impact to productivity and eventually cost and schedule. Working in a controlled environment, which is offsite from the client, also allows for ease of maintenance of sanitized workspaces with a smaller concentration of crew members.

5. **Reduced commercial and contractual risk.** Decreased productivity, schedule delays, rising project costs, among others, resulting from a COVID-19 environment, present themselves eventually as commercial and contractual risks, such as liquidated damages and a possible *force majeure.* By leveraging the inherent benefits of modularization, suppliers and owners can minimize the likelihood and/or severity of such commercial and contractual risks.

The geography of the pandemic. Unlike field construction, modularization is not geographically constrained to the plant site. If a customer's site is in a region where there is a high risk of COVID-19 exposure, the fabrication of the modules is location independent; therefore, a fabrication site that is in a state where COVID-19 has a much lower prevalence can be selected.

In general, modular construction can ensure safer construction because the assembly area can be restricted to have as few as one or two workers in a horizontal orientation separated by much more than 6-ft. However, on larger projects, it is even possible to split the fabrication across two or more geographically separate assembly locations, minimizing the number of modules and workers present simultaneously, thus reducing the risk of project interruptions should a COVID-19 outbreak occur at one of the fabrication sites.

By applying the inherent health and safety, quality, cost and schedule benefits and leveraging them in a COVID-19 environment, owners can lower project delivery risk to manageable levels; therefore, enabling sound project go/no-go decisions. Our industry is built on projects and employing a modular project delivery model during a COVID-19 environment can be the path to successful project delivery during these times of uncertainty. Flexibility, creativity, resourcefulness and social responsibility have become key characteristics of project execution across the oil and gas and chemical industries. HP

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Challenges and pitfalls in brownfield EPC projects

Job requirements and scope are well defined in engineering, procurement and construction (EPC) contracts because they are designed and engineered from scratch. Owners prefer to get work done through EPC contracts as it helps them in obtaining a firm cost and time commitment.

Executing a brownfield project in a process plant presents many challenges and complexities due to unknowns and potential variations. Major factors include the non-availability of old data drawings, design calculations and updated/as-built drawings.

Normally, small brownfield projects are preferred on a cost-plus basis, as engineering and execution go side by side and uncertainties are identified as the job progresses.

Considering the advantages of an EPC contract, owners usually prefer to pair brownfield work with any upcoming greenfield expansion projects. This makes the project attractive to an EPC contractor, and the owner can also get firm cost and schedule commitments. Time issues becomes more complex when more than one or two EPC contracts are awarded in the same or adjoining field, sharing some common facilities, space and working areas. In such cases, the interdependency of the two contractors also increases.

Some of the challenges and lessons learned while executing such hybrid projects are presented here. Although these issues may appear to be standard, they can have serious consequences if not considered during a cost estimation. Normally under such contracts, the owner and its team (or PMC) earnestly intend to provide all details at the enquiry stage. However, they try to cover any out-of-sight discrepancies by using a typical clause:

> "Details provided in the inquiry document are the best possible at the time of release of this document. However, these are subject to field verification by the contractor prior to submission of bids. Unless any exceptions or deviations are put forward by the contractor and accepted by the owner, any subsequent changes later shall not be acceptable, and time and cost implications shall be to the contractor's account."

Some common types of design and execution challenges are detailed here.

Process area. Process conditions at the battery limits of any operating plant are dynamic and expected to have variations that must be detailed in the inquiry for the contractor to conduct a hydraulic check. In a project, due to this omission, one acid gas collection required an increased stainless-steel header size at a late stage; as available gas came to it from different units, the pressure was insufficient to reach to the downstream sulfur recovery unit (SRU).

In an integrated analysis of a complementary brownfield with greenfield project, complete hydraulics and pressure balancing is required for systems like air, cooling water, steam, flare, etc. In another project, a problem was encountered with cooling water supply pressure and quantity, resulting in the augmentation of the old plant cooling water system.

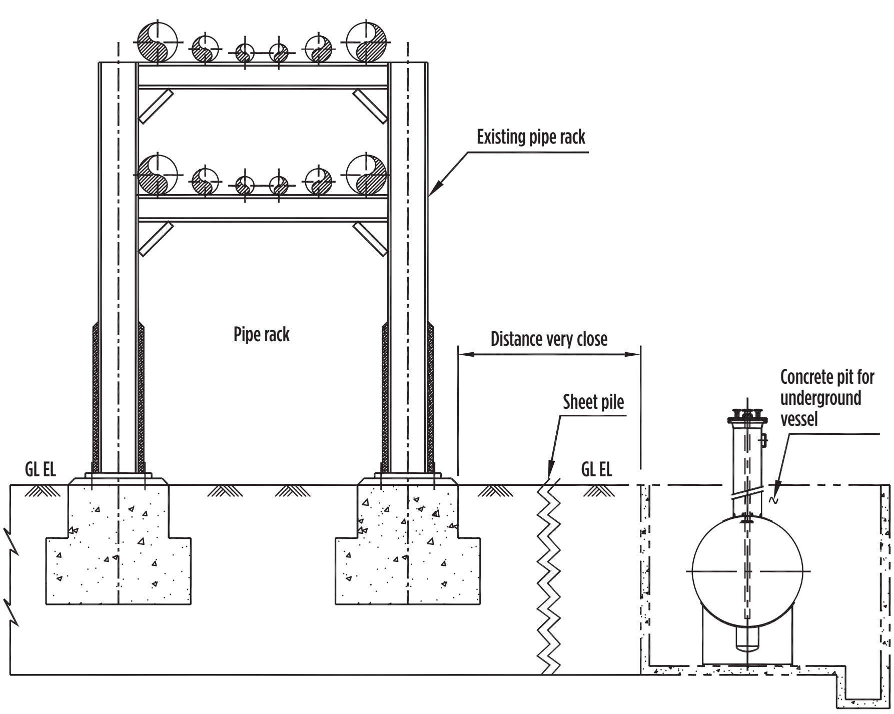

FIG. 1. During excavation, sheet piling was used to protect the foundation of a pipe rack.

Metallurgical improvements occur regularly in the process industries. The extent of implementation of superior metallurgy in brownfield modifications should be demarcated clearly along with the greenfield project. The construction material of piping, instrumentation and equipment internals, etc., should be clearly marked on a material selection guide (MSG) and material selection diagram (MSD) to avoid the confusion of a superior metallurgy change in the old units.

Demolition and cleanup of any old unit. Demolition of an old unit and site clean-up to create space for a new unit is normally part of any project. The scope normally covers the removal and disposal of old equipment, piping, foundations and structure in a safe manner.

The area should be inspected for hidden surprises, such as underground cables, pipes, drains or any process lines and old foundations. The area should be thoroughly scanned by suitable tools (ultrasonic or other type) to avoid damage to any live system.

Any adjoining building or structure that is live and may get impacted during excavation work should be identified and an accordingly suitable reinforcement of structure must be planned.

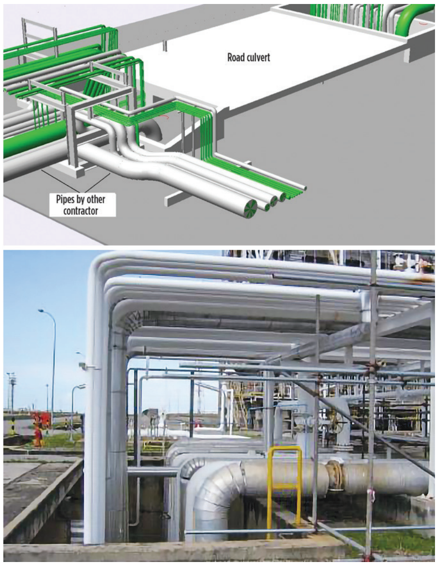

FIG. 2. A new culvert was designed to carry pipes of two EPC contractors.

Excavation work near existing building/structure. Soil condition, depth and angle coverage of excavation, and distance from any existing structure or pipe rack should be ascertained before proceeding with excavation.

In one project, the soil condition was found to be very unstable. Excavation was required for the construction of a concrete pit to stall an underground slop tank. Excavating close to the existing pipe rack could have damaged its stability.

The project personnel had to either shift the location of the pit or use sheet piling, as shown in **FIG. 1**, to protect the foundation of the pipe rack. Shifting the location was not possible without major engineering changes, so the second option of sheet piling was used.

Mechanical functional area. Front-end engineering design (FEED) should normally cover all relevant data, drawings and health check reports of existing equipment (where modifications and alterations are planned).

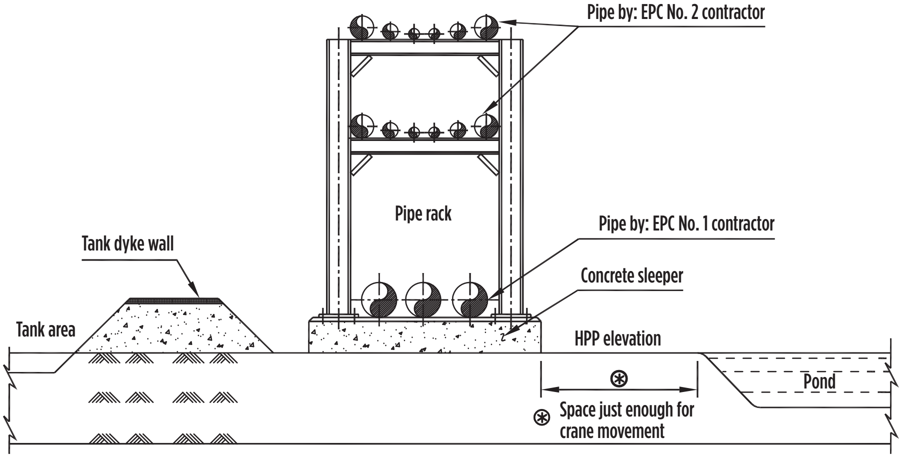

FIG. 3. To allow two contractors to carry out piping work between a tank dike wall and a pond, with little space for vehicular/crane movement, a goal post-type frame was mounted on concrete sleepers.

Similarly, an equipment health check on equipment, the foundations size and depth, current condition and preferably the old design calculations should also be available.

Any change in old equipment loading data due to change of internals will have an impact on the foundation. Significant changes can occur in equipment design conditions, design codes, stress values, wind and seismic conditions, etc.

Another project faced a height increase requirement of a distillation tower to accommodate an extra packed bed in the top section. Because an increase in the column height in the top section was needed, the column design required a complete review based on the latest codes, standards and new design conditions. However, the old foundation details and design calculations were unavailable, and it was challenging to carry out a health assessment of the old foundation and justify its adequacy.

Similarly, stress relieving and hydrotesting of an old column after modification are other important issues, considering the need to safely hold the tower during heat treatment to check the suitability of an old foundation for hydro test load.

Civil and structural area. When modifying or retrofitting any existing technology structure, pipe racks, road bridges, and where process equipment, agitators, etc., are added, an evaluation is required for all static and dynamic loads, along with their foundations as per the latest rules, design codes and regulations.

Piping functional areas. Tie-in points locations and accurate piping end connection details are vital. In a project, the line/flange size of one tie-in could not be ascertained, as it was at a high elevation and unapproachable. The information provided by the operators was relied upon. However, during execution, the pipe size was found to be different; this resulted in a last-minute rush for design changes, approvals and material procurement. Pipe metallurgy, size, flange facing and rating, type of gasket and provisions for piping isolation valves must be carefully checked for each tie-in.

Isolation valves are normally the

preferred choice as they do not require upstream shutdown. However, the operability of these isolation valves must be checked, and they must be kept in proper serviced condition.

All tie-in points must be tagged with tag numbers (the preferred method is to have non-metallic plates with painted or embossed numbers). A location coordinate table of all tie-ins should be marked in piping layout drawings.

A unique problem of different material specifications of PMS between two EPC contractors at tie-in points has been encountered—this difference is difficult to justify to an owner.

Piping corridors. The author has encountered the sharing of available space in existing pipe bridges racks, road culverts and pipe ways with another contractor. **FIG. 2** shows where a new culvert was designed to carry pipes of two EPC contractors. The design was complicated due to a "T" joint and a side-by-side passage through a road crossing. This required many joint sittings of the two contractors with the PMC. An agreement was required to determine the roles and division of work within the culvert area between the two contractors, in addition to the issue of material supply, to avoid clashes between the two teams.

Similarly, in another case, a very narrow space was available for two contractors carrying out piping work between a tank dike wall and a pond, and with little space for vehicular/crane movement (**FIG. 3**).

One contractor's scope was to lay large trunk pipelines on a concrete sleeper, while the other contractor had too many smaller pipes on a "T" post or pipe rack, running parallel as per the original contract. The original design eliminated space for crane or vehicle movement. Both contractors agreed to a common type of supports. A goal post-type frame mounted on concrete sleepers (**FIG. 3**) proved to be a win-win solution.

Instrumentation. This can be the most troublesome part in any brownfield project if it is not properly conceived by the owner and clearly explained to the EPC contractor.

Technological advancements are continuously emerging on types of instrumentation, communication, EMC and RFI feature compliance.

If the previous plant control room was an older generation, then the owner must ensure that changes and revisions are duly implemented and the compatibility of field instruments with the control room is addressed.

Upgrading software is required as part of control system integration of instrumentation, as well as cybersecurity and confidentiality requirements.

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Retrofit: A viable alternative to greenfield construction

Retrofitting/revamping—also referred to as modernization, derating or rerating—is an update of a plant or an existing piece of equipment to improve efficiency and/or capacity, and to make it adequate for a new design or operating condition through the modification or replacement of some of its parts. New parts/equipment may be added to make the equipment and/or the plant adhere to demand. High-efficiency internals replace old ones, and some equipment parts are removed and replaced with new ones. For example, FIG. 1 shows a sketch for a typical fluid catalytic cracking (FCC) reactor-regenerator revamp. In this case, the existing regenerator is being retrofitted to cater to increased demand by replacing the cyclones, the dome, the air distributor, slide valve, spent catalyst deflector and linings (all highlighted in yellow and blue ink), while retaining the existing shell. The number of cyclones and the air distributor configuration were revised, and the existing design was checked for adequacy for loading conditions.

Retrofitting.

Several reasons exist why retrofitting a plant or unit is the most efficient option for owner-operators. Clients and investors are looking to optimize investment costs and are seeking a quick return on investment (ROI) and the production of better products. New greenfield projects are challenging due to their high investment costs and construction time frames. Owners are also looking for quick solutions to enhance the quality and quantity of existing energy products. Whether it is a large oil and gas project or a small chemical project, each company strives to increase existing plant capacity and product quality in a timely manner (i.e., reducing downtime).

Retrofitting/revamping includes the following objectives:

- Increased equipment design life
- Improvement in efficiency/throughput
- Relocation of equipment/machinery
- Testing of the latest technology
- Increased energy savings
- Improvement of maintenance and safety of operation
- Adherence to environmental strains or legislational changes
- Quick ROIs.

These objectives make retrofitting a sought-after solution for energy companies.

Retrofitting from a detailed engineering point of view.

Equipment and internals have a set lifecycle per the client's project-specific requirement. Most of the static, rotating and fired equipment, as well as the piping, have a design life of 20 yr–30 yr—whereas, internals (e.g., tubes and column internals) are designed to last for 10 yr–20 yr. Accordingly, corrosion allowances are built into the design. After a certain period of usage (i.e., age of equipment), equipment and components are degraded due to pressure, temperature, weight, vibration, environment, site conditions and flow transients. Most equipment undergoes at least one revamp during its lifecycle.

The author's company has recently executed a study and detailed engineering activity for retrofitting a chemical plant. The old plant was in operation, producing products that adhered to local regulations. The author's company carried out the study

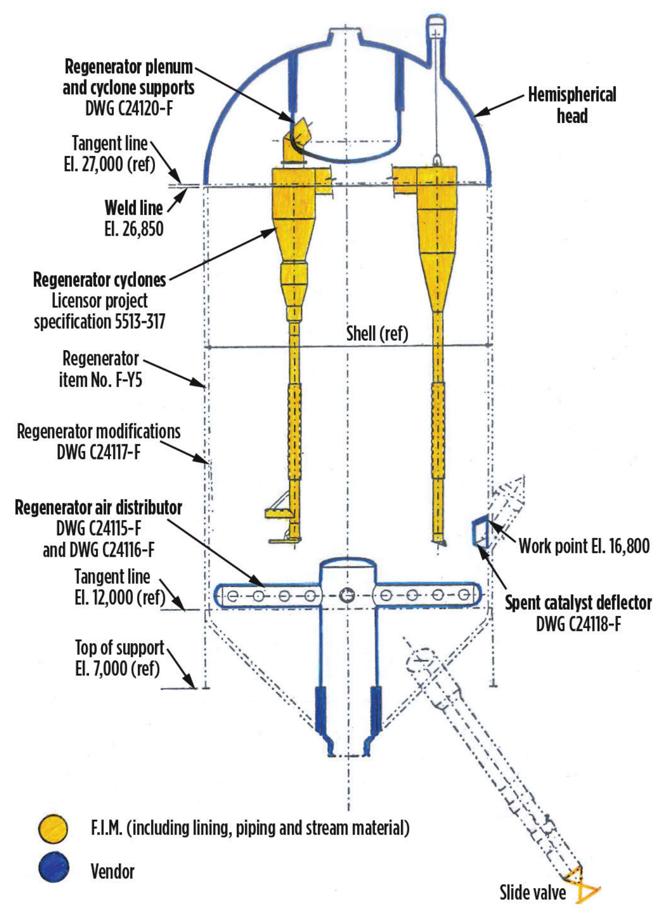

FIG. 1. Sketch of a typical FCC regenerator retrofit.

to ensure that the plant's equipment and facilities were still fit for service. Fitness for service (FFS) purpose or mechanical integrity is a set of quantitative methods used to determine the integrity and remaining life of degraded components and to help operators make run-or-repair decisions.

Project managers and engineers visited the plant site for an initial evaluation. From visual inspection, various fabrication deficiencies and concerns were flagged by the team. These observations included the following:

- Standard products for various equipment components (e.g., nozzle flanges, blind flanges, studs and bolts) were not used (**FIG. 2**).
- Geometrical configurations (thickness and diameter) for various equipment components did not comply with that of standard products.
- Mismatch of equipment details with that shown in as-built drawings.
- Defects and cracks in equipment were clearly visible.
- The subpar quality of fabrication, welding and repair work were clearly noticeable (**FIG. 3**).

Based on these observations, an adequacy check of the plant and its equipment was carried out based on available drawings, documents and site survey reports. Most of the facility and equipment failed this adequacy inspection, based on the following:

- Code of construction (ASME vs. local standard)
- Operation methodology
- Source of equipment
- Fabrication quality
- Product standardization.

FIG. 2. Standard products for equipment components were not used.

FIG. 3. The quality of fabrication, welding and repair was subpar.

Most of the equipment was fabricated and operated as per local codes and plant operation methodology. These are based on FFS and do not meet the requirements or codes mentioned in the fabrication/as-built documentation. The client who purchased the plant decided to retrofit/revamp the existing plant and to increase capacity to make retrofitting economically viable.

In a separate project, a Middle Eastern client purchased equipment from a Western country and transported it to the proposed site. Most of the equipment was retrofitted/revamped to make it suitable for the design and operating conditions of the proposed plant. This was a challenging management decision, as many cost factors involved in retrofitting (such as the cost of existing equipment, logistics, transportation, retrofitting and re-installation) needed to balance out the costs of new equipment fabrication and installation. The risk involved in anticipating the cost of retrofitting vs. new equipment installation was substantially high due to the uncertainty in estimating all types of cost in retrofitting. FFS relies on comparing the demand on the degraded component/equipment (e.g., the load exerted in-service in the form of pressure, temperature, weight, vibration and flow transients) to the components' capacity to sustain demand.

With greenfield plants being capital intensive and having longer construction timelines, retrofitting an existing plant and equipment can be a viable option to meet product demand. Operating companies must have proper planning and documentation to greenlight a retrofitting project to meet current market demand and to maintain a grasp on the latest technologies and environmental legislation. Some of the key factors to consider include:

- As-built drawing test reports and material certificates
- Periodical equipment health check reports during planned maintenance and inspections
- Remaining-life assessments for equipment, based on present operating and design conditions
- New regulations and legislational changes
- Planned capacity/efficiency improvements
- The quality of the finished product.

All these factors must be assessed meticulously before greenlighting a retrofit on an existing plant. Other factors appear when equipment modifications, relocations, reinstallations and testing are carried out. These costs can impact an owner's planned retrofit project budget. Technical risks include:

- Specificity of works and experience of engineers/designers
- Primary parties involved in the project (such as fabricators and construction contractors)
- Technology used and compatibility between new design specifications and the original design
- Technical safety margins on upgraded machines
- Conservation measures during standstills
- Logistics and security on working sites.

Various equipment codes boilers, pressure vessels, storage tanks and pumps also need to be verified during a retrofit project.

Takeaway. Retrofitting a plant or existing equipment is a viable option for oil and gas operators, as well as for chemical manufacturers. All parties must efficiently optimize their workflows to optimize costs and to increase the quality of the facility's products, while adhering to regulations. The items presented here will help operators to minimize risk during retrofitting operations. HP

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Design considerations when flaring ethylene oxide

The flaring of gases released from normal process vents and safety valve discharges following an overpressure scenario is widely practiced in refineries, petrochemical and chemical plants. In past projects, ground flares, elevated flare stacks or a combination of these two systems have been successfully used for the flaring of pure ethylene oxide (EO) or EO-rich streams. However, the flaring of pure EO or EO-rich streams requires certain additional precautions, as well as several stringent design and safety considerations due to it being unstable, toxic, highly reactive and flammable. In addition, EO was often vented off from high point vents directly to the atmosphere in many older plants. Since EO is toxic and a known carcinogen, the disposal of large quantities of EO or EO-rich streams from process vents and safety valve discharges by direct venting to the atmosphere has raised environmental concerns in recent years.

EO is the simplest cyclo-ether. It is a colorless gas at room temperature, with a sweet etheric odor and is prepared by reacting ethylene with air or oxygen over a silver oxide catalyst. EO is a good sterilizing agent and is also used to treat foodstuff. However, EO is generally further reacted with other chemicals to produce EO derivatives, the most important being ethylene glycol which is used to manufacture polyester and automotive antifreeze. EO is an important raw material in the manufacture of ethanolamines (used in the production of soaps, detergents and textile chemicals), ethyleneamines, glycol ethers (e.g., solvents for surface coatings) and polyurethanes.

The two reactions of EO of special note are the following:

1. **Decomposition of EO:** EO vapor or EO vapor mixed with air can decompose explosively, generating carbon monoxide and methane. This exothermic reaction is represented in Eq. 1:

$$C_2H_4O \rightarrow CO + CH_4 \quad (1)$$

2. **Disproportionation of EO:** Disproportionation of EO—which consists of a reduction-oxidation reaction—can result in the production of ethylene and carbon dioxide. It is typically represented by Eq. 2:

$$4C_2H_4O \rightarrow 3C_2H_4 + 2CO_2 + 2H_2 \quad (2)$$

Design considerations. Owing to its unstable, toxic, highly reactive and flammable nature, a standalone EO flare system (piping, knockout drum, liquid seal drum and flare stack)—used for the disposal of vapors containing EO or EO-rich streams—should take into account special design and safety requirements. It must be emphasized that a detailed design and safety review should be performed on the piping and instrumentation diagrams of the EO flare system before it is engineered. Furthermore, strict operational and safety considerations need to be enforced during the operation of the system. The following are the main design considerations that should be considered when designing an EO flare system.

Rupture disc upstream of the pressure relief valve (PRV). The two most used relief devices in the process industry are rupture discs and PRVs. Owing to their non-closing nature, rupture discs should not be used in EO service. When relieving EO, a rupture disc should be installed upstream of the PRV to prevent the build-up of solids or blockage at the inlet to the PRV. Solid deposits at the safety valve inlets could form as a result of EO polymerization. All PRVs used in EO service should conform to the requirements of API 520 and API 521. Furthermore, the PRV should be de-rated due to the upstream rupture disc and a capacity correction factor of 0.9 should be used.[1]

Minimization of the relief device inlet pipe length. The inlet pipe length from the source (i.e., vessel or column shell) to the relief device should be minimized, as pockets of stagnant EO vapor in a long inlet line could lead to EO polymerization. This can result in a build-up of solids, which, if unchecked, could ultimately lead to a blockage of the line, leading to a hazardous situation in the plant during a major relief scenario.

Purging requirements. As practiced in a typical hydrocarbon flare network, a normal fuel gas or natural gas purge must be provided at all flare header and sub-header dead ends to maintain a small positive velocity in the header or sub-header.[2] This should be backed up by nitrogen to increase the reliability of the purge.

However, in addition to the normal purge, an emergency purge must be provided for the EO flare. The main function of the emergency purge (natural gas or nitrogen) is to sufficiently dilute the EO-rich stream to make it non-explosive. It must be ensured that the emergency purge is always available.

The availability of the normal and emergency EO flare purges is one of the most critical considerations for an EO flare and must be closely monitored. These purges are essential for the uninterrupted operation of the connected plant. It is highly risky to operate the plant if there is a failure of either one of these purges and strict operational procedures should be enforced to monitor the normal and emergency purges on a routine basis.

The concentration of EO diluents is a function of the pressure and temperature of the system. In the absence of air within

the system, the concentration of diluents required to keep the system non-explosive must be more than 15% methane (considering a binary mixture of EO and methane) or 40% nitrogen (considering a binary mixture of EO and nitrogen).[3] However, it is recommended that an appropriate factor of safety (around 2-3) should be imposed on these limits, owing to the limited availability of data at higher temperatures.

It must be emphasized that a detailed design and safety review should be performed on the piping and instrumentation diagrams of the EO flare system before it is engineered.

To improve the reliability of the EO flare system, the emergency natural gas purge should be automatically backed up by nitrogen using a SIL-rated interlock. A pressure sensing system—consisting of two or more pressure transmitters placed between the rupture disc and the PRV inlet—should be used for all PRVs, which could potentially release pure EO or EO-rich streams to the EO flare. During an overpressure scenario, the rupture disc would rupture and the high pressure at the PRV inlet would be used to trigger the emergency purge. One or more additional pressure transmitters can be located at each PRV discharge to further increase the reliability of the system.

Flare gas analyzer. A flare gas analyzer (e.g., a gas chromatograph-based analyzer that is sensitive to 1 ppm of EO) located on the main flare header can be programmed to trigger the emergency flare purge in case the concentration of EO or oxygen exceeds a certain fixed value.

Materials of construction. Any piping and/or equipment that can come into contact with the EO-rich stream must be made of stainless steel (SS). The use of SS minimizes the potential for rust formation. The 300 series austenitic SS has been widely used in EO service. Type 304L has been successfully used for the EO flare headers and sub-headers, while Type 304 and Type 316 SS have been used for small tubing, which cannot be cleaned of rust. Austenitic SS can be used in those areas where EO liquid is likely to remain for long periods of time (suction and discharge piping of flare knockout drum pumps, low point drains, etc).

Traces of rust on the internals of carbon steel piping or equipment would catalyze the disproportion of EO, which would further raise the local temperature above the EO decomposition temperature, leading to a hazardous situation. Furthermore, even clean carbon steel could catalyze the polymerization of EO but at lesser rates than rusted carbon steel. Therefore, the use of carbon steel piping and equipment in an EO flare network should be prohibited.

Since EO attacks several non-metallic materials, including several types of polymers and elastomers, proper care should be taken to select a proper material of construction for gaskets, O-rings, packing, etc. This would include rigorous monitoring and inspection programs before a material is deemed fit for use in EO service. Polytetrafluoroethane (PTFE) is resistant to EO even up to 260°C and has been used successfully in such applications.[3]

Grounding requirements. EO liquid is conductive. If EO is stored in a metallic container that is grounded, the static charge cannot accumulate. However, if the system is not properly grounded, a static charge can be generated and lead to ignition—owing to the low value of the minimum ignition energy of EO, which is even lower than gasoline vapor.

Therefore, all EO flare system components (including piping and equipment) must be properly grounded to prevent the build-up of static electricity, which could ignite EO and start a fire or explosion.

Prevention of flashback. A flare system is usually equipped with a liquid seal drum to prevent flashback. However, this method suffers from some drawbacks due to the possibility of losing the liquid seal (e.g., if the seal gets blown out following a peak release or if there are issues in establishing and maintaining the required liquid level). The use of two liquid seal drums in a series—one located at the base of the flare stack and another located between the outside battery limits flare knockout drum and the stack—can further enhance the reliability of the EO flare liquid seal system.

In the case of EO flares, the flare tip contains an anti-flashback device (velocity section), which must be designed to minimize possible flame flashback initiated at the flare tip by ensuring that the forward velocity of the flared gases exceeds the flash-back velocity.[3] Furthermore, an appropriate velocity seal would need to be provided to prevent air ingress and conserve purge gas. Close follow-up with the flare vendor is recommended at every stage during the design of an EO flare system to increase the reliability of the system in view of the hazards associated with EO. Per flare design regulations followed in some countries, (e.g., Russia), the possibility of including a spare flare stack, liquid seal drum system and knockout drum may also be considered to further increase the availability of the flare system; thus, ensuring uninterrupted operation of the connected units.[4]

Sampling of flare condensate. Flare condensate collected in the flare knockout drum must be periodically sampled. Any EO-containing flare condensate is required to be routed to the reabsorber column or elsewhere inside the EO unit for further recovery of EO. However, if the flare condensate does not contain EO, it may be routed to wastewater treatment. This can be accomplished through an interlock based on the EO concentration as measured by an on-line analyzer. HP

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Determining the indeterminate

Standards such as API, ASME and NFPA are applied widely in the refining industry. These standards indicate background statements and the area of applicability. The case study presented in this article shows that analyzing these background statements can improve the design with respect to operational flexibility and environmental aspects without compromising safety attributes. This case study examines NFPA 86 requirements, revealing the uniqueness of the sulfur recovery unit (SRU) incinerator, with respect to the applicability of the standard in the furnace design.

The incinerator in an SRU. The SRU acts as the sulfur sink for the overall facility or complex. Since crude oil always contains varied amounts of sulfur components, an SRU exists as an inherent part of any refinery. The sulfurous compounds in the refinery feedstock are removed in the form of hydrogen sulfide (H_2S) via various processes, which is delivered to the SRU. The SRU captures the sulfur from the H_2S-rich streams to prevent it from being transmitted to the atmosphere either as toxic H_2S or harmful sulfur oxide (SO_x), while producing sulfur either in liquid or solid form. The SRU limits the sulfurous emissions within the allowable norms and standards as applicable for the specific location. Hence, the continued operation of the SRU is essential from an environmental aspect.

The incinerator or the thermal oxidizer section of the SRU serves the purpose of completely burning all H_2S-containing streams in the SRU block that are not suitable for further recovery or processing. **FIG. 1** provides a block flow diagram of the SRU, with a special emphasis on the interaction of the incinerator block with the rest of the unit.

The main sources of offgases to the incinerator come from the tail-gas treating unit (TGTU) (Stream 2), typically from the top of the amine absorber column. In most SRUs, there is flexibility in routing the Claus offgases directly to the incinerator in the event the TGTU becomes unavailable (Stream 1). Other typical sources of offgases to the incinerator include the vent gases from the degassing section (Stream 3). The vent gases from the degassing section preferably are routed to the Claus section of the unit as recycled gas, but the alternate route of sending it to the incinerator is always present in the design. Another source of vent gas is from the sulfur storage tanks (Stream 4). Even though degassed liquid sulfur is typically stored in the tanks, a sweep gas flow is generally maintained to avoid the possible buildup of H_2S vapors inside the tanks. This stream is routed to the incinerators with the help of ejectors (steam or air driven).

The SRU's incinerator is designed to burn the residual unrecovered sulfur in the form of H_2S from all vent gas streams (**FIG. 1**). Fuel gas and air in excess to the stoichiometric amount is supplied to the incinerator to maintain a firebox temperature of approximately 750°C–800°C. This temperature, along with the excess air always present in the firebox, ensures nearly complete combustion of the H_2S to form SO_x. The flue gas stream containing small amounts of SO_x (within allowable limits) is then vented into the atmosphere through the stack.

NFPA 86 and the SRU incinerator. Typically, the SRU incinerator design follows the guidelines stated in NFPA 86 (the standard for ovens and furnaces). The typical recommendations mentioned in this standard are all applicable in the design of the SRU incinerator, as is the case for any general furnace in the refinery. The NFPA 86 guidelines form the basic recommendations for such furnace designs followed globally to ensure the safe design of the incinerators.

An essential statement in the NFPA relates to safe startup of furnaces. The specific clause in the NFPA 86 2015 Clause A.8.5.1.2(C) or NFPA 86 2019 Clause A.8.5.1.2.3(1) states that equipment such as thermal oxidizers commonly process sources of contaminated air. Contaminated air is an indeterminate purge medium. Design of the pre-ignition airflow interlocks should incorporate a means to prove a source of fresh air and prove the

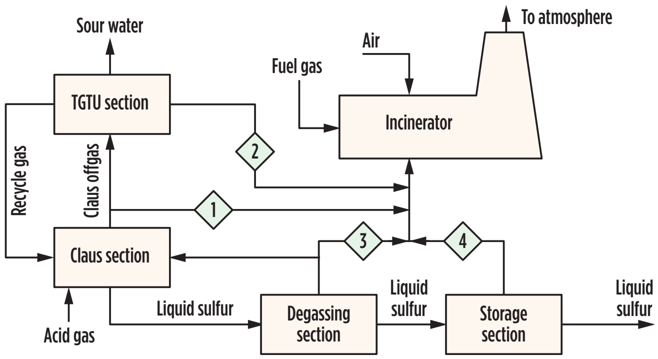

FIG. 1. Block flow diagram of a typical SRU.

isolation of contaminated air sources during pre-ignition purge. In complex systems involving multiple sources where it is not always possible to shut down all indeterminate sources, providing a fresh air source and positive isolation from all contaminated sources is necessary to ensure proper pre-ignition purging.

An SRU incinerator is unique, with respect to the applicability of the NFPA 86 standard in furnace design.

This is an extremely important statement related to the safe operation of the furnace. Before furnace startup, the atmosphere inside the firebox must be inert with respect to any fire hazards. To ascertain this inertness, and to avoid the possibility of an explosion during the startup, the firebox must be purged with air or any other inert medium. During this purging, all other sources or feed streams to the incinerator need to be stopped. This is required due to the uncertainty of the actual composition of the gas mixture inside the firebox. For an incinerator, which typically burns off waste streams from various sources, the composition of the source gases may vary within a wide range—hence, the composition of the gas mixture inside the firebox can be indeterminate. To mitigate this unknown factor of the gas composition, the startup purge sequence is completed by shutting down all feed streams to the furnace to ensure the safe startup of the incinerator.

The SRU incinerator is unique since the feed gas streams to the incinerator are all coming from controlled process systems that allow the gas compositions to be limited within a specific range. In a way, the SRU incinerator feed streams are not "indeterminable" or unknown. Proper assessment of the system by the design engineer will allow certain liberties to be taken with respect to the startup purge sequence of the incinerator, without making any compromise on the safety aspect of the operation. The following case study will provide a few typical data samples to show how the composition of the feed gas streams to the incinerator may be determined and how that allows some flexibility in the design and operation of the SRU, with a beneficial effect on safety and plant emissions.

TABLE 1. H_2S concentrations in vent gas streams

Stream no.	1	2	3	4	
Stream description	Claus offgas	Offgas from TGTU	Degassing section vent gas	Tank vent gas	**Total vent gas**
Case 1	N/A	20 ppmv	0.02%	0.05%	**140 ppm**
Case 2	N/A	20 ppmv	0.02%	0.5%	**0.02%**
Case 3	N/A	200 ppmv	0.02%	0.5%	**0.03%**
Case 4	0.58%	N/A	0.02%	0.5%	**0.31%**
Case 5	0.58%	N/A	N/A	0.5%	**0.58%**

TABLE 2. H_2 concentrations in vent gas streams

Stream no.	1	2	3	4	
Stream description	Claus offgas	Offgas from TGTU	Degassing section vent gas	Tank vent gas	**Total vent gas**
Case 1	N/A	2.5%	0%	0%	**0.85%**
Case 4	2.9%	N/A	0%	0%	**1.26%**
Case 5	2.9%	N/A	N/A	0%	**2.85%**

Case study data. This case study had all of the possible four vent gas streams feeding into the incinerator (**FIG. 1**): the Claus offgas or the TGTU offgas, the vent gases from the degassing section and the tank vent gases. Two unique design aspects exist in this SRU incinerator. First, the vent gases from the degassing section are always routed to the incinerator, with no option for them being sent to the upstream Claus section. The unit was able to achieve the targeted sulfur recovery efficiency even without this recycle of the vent gases to the Claus section. Secondly, the liquid sulfur storage system—normally expected to hold pure degassed sulfur—had the option to have undegassed sulfur containing high H_2S. Therefore, the venting system on the sulfur storage system was designed to handle high-H_2S-containing vent gases from the sulfur storage section. Another constraint in the SRU design in the case study refinery was that, although the SRU was a multi-train design, there was hardly any operating flexibility or spare capacity available in the total sulfur handling capability. This meant that, if one SRU train shut down, there would be a significant amount of acid gas flaring—hence, SO_x emissions.

Typically, whenever the SRU incinerator section would trip, the upstream Claus section, TGTU section and degassing section would also need to shut down, leading to a total SRU shutdown and consequent acid gas flaring from the upstream amine regeneration unit and sour water stripper. To improve the availability of the SRU, a flexibility on the SRU logic was considered as a design improvement—this being a 1-hr delay in the tripping of the entire SRU once the incinerator shuts down. This would allow the SRU to continue running for 1 hr, even without the incinerator—thus providing the operator a chance to bring the incinerator back into operation without shutting down the SRU.

One major hindrance in the successful application of this logic was the NFPA clause, which mandates that the feed streams to the incinerator must be isolated due to their gas compositions being indeterminable. Therefore, a detailed analysis of the streams was performed to determine the gas compositions. The initial focus of this study was directed to assess the amount of H_2S in the vent gas streams.

TABLE 1 provides the H_2S composition data for the offgas streams for the various cases covering typical SRU operations:

- **Case 1: Normal operation of the entire SRU**—No gas from the Claus section, on-spec operation of the TGTU, vent gas from the degassing section and normal vent gases from the storage area.
- **Case 2: Degassing in the storage area**—No gas from the Claus section, on-spec operation of the TGTU, vent gas from the degassing section and high-H_2S-containing vent gases from the storage area.
- **Case 3: Process fluctuation in the TGTU unit**—No gas from the Claus section, operational upset in

the TGTU leading to sulfur slippages, vent gas from the degassing section and high-H_2S-containing vent gases from the storage area.

- **Case 4: TGTU bypass case**—Offgases from the Claus section, no offgas from the TGTU, vent gas from the degassing section and high-H_2S-containing vent gases from the storage area.
- **Case 5: Maximum possible H_2S**—Offgases from the Claus section, no offgas from the TGTU, a non-operational degassing section and high-H_2S-containing vent gases from the storage area. This is a very abnormal condition for the SRU, where both the TGTU and the degassing sections are shut down when the incinerator trips, with only the Claus section running normally, and associated degassing to occur from the sulfur storage area. This was only considered mainly for the purpose to assess the maximum possible H_2S concentration in the combined vent gas stream to the incinerator.

The analysis of the data provided in **TABLE 1** shows that there are no concerns with respect to fire hazards in the incinerator due to the presence of H_2S in the vent gas streams vs. with the H_2S flammability limit being 1.6% [considered at 40% of the lower explosive limit (LEL) for H_2S], even with the very conservative case (Case 5).

The second component of interest is hydrogen (H_2) from the TGTU section—or from the Claus section with the TGTU being bypassed for some operational reasons. The assessment was made to calculate the H_2 content in the overall stream to the incinerator. **TABLE 2** provides data for the various scenarios. The cases reported in **TABLE 2** also correspond to the definitions already provided in **TABLE 1**. The H_2 data is reported only for three cases, as no H_2 is present in the vent gas streams from the degassing area and the sulfur storage area.

The data provided in **TABLE 2** shows that the H_2 concentration is of concern, with respect to fire hazard, only for Case 5. The amount of H_2 content in the incinerator is above the threshold limit; the threshold limit is typically defined as 40% of LEL (4% for H_2, so 1.6 vol% H_2). All other cases are well within the threshold limit.

Therefore, under normal SRU operating conditions (Cases 1, 2 and 3), the vent gases to the incinerator pose no fire hazard concern. The only point of concern is during the TGTU bypass scenario with respect to the concentration of H_2 in the offgas streams. A safety measure was implemented in the logic to not allow for a startup of the incinerator in case, simultaneously, the TGTU was also not operational. Health check feedback from the interlock for the TGTU section was provided as a startup permissive to the incinerator. Therefore, the incinerator could start up even with the vent gas streams from the TGTU, the degassing section and the storage section flowing into the firebox of the incinerator, since they were determinable and safe. This configuration of the vent gas streams being equivalent to the normal operating condition meant that the overall availability of the SRU was increased. For every incinerator section trip, the entire SRU typically does not need to shut down (with each case dependent on given safety concerns); therefore, improving SRU availability and avoiding significant emissions from the acid gas flare and, hence, from the entire refinery.

Takeaway. NFPA 86 mandates that all streams to any incinerator must be isolated before a safe and successful purge of the furnace is allowed, as the gas compositions of the vent streams are "indeterminable" in many furnaces. For an SRU incinerator, the composition of each of the individual offgas streams can be determined, to an acceptable degree of accuracy and confidence, with a conservative approach—consequently, these compositions are no longer "indeterminable." Analysis reveals that the vent gas streams will not pose any specific fire hazard threat, and, based on the results of the analysis, highlighted design modifications on the startup logic of the incinerator may be implemented to allow for a safe startup of the incinerator without tripping the entire SRU. This design flexibility improves the overall availability of the SRU, thereby leading to a lesser amount of acid gas flaring—thus providing a greener, but still safe, SRU design. HP

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Take control of tank pressure

Maintaining pressure control in bulk storage tanks is a vital challenge faced by operators of both process plants and storage terminals. Although they may not get the same level of attention as other parts of the plant or facility, storage tanks present many inherent risks to personnel, the environment and equipment if not properly maintained.

The tank farm of a refining or chemical complex is a relatively low traffic area and is often maintained by junior operators. The devices maintaining tank pressure are usually located on the top of the tank and only accessible by tall stairs or ladders, scaffolding or catwalks. As a result, these devices are often out-of-sight and out-of-mind, presenting operators with increased risk. Many tanks do not have the capability to signal an abnormality to the crew on shift, so issues may linger unresolved for long periods of time (**FIG. 1**).

According to American Fuel and Petrochemical Manufacturers (AFPM) statistics, 12% of Tier 1 and Tier 2 safety incidents involve storage tanks, with refineries and terminals accounting for 74% of these incidents.[1] A large percentage of incidents can be attributed to personnel error or equipment failure, most of which result in fires or explosions.

In addition to equipment damage, downtime and possible personnel injury, these incidents can put the general public at risk. According to the U.S. Chemical Safety and Hazard Investigation Board's analysis[2] of the U.S. Environmental Protection Agency (EPA) Toxics Release Inventory (TRI) Database[3], 77% of bulk terminal locations are located within one mile of communities of 300,000 residents or more.

For these and other reasons, it is vital to monitor and control tank pressure in hydrocarbon plants, facilities and storage terminals.

Issues and risks. Operators must ensure each tank operates in its normal pressure band, with the appropriate equipment installed to prevent overpressure or vacuum conditions. An overpressure condition could lead to a tank rupture, and an underpressure condition could lead to an implosion (**FIG. 2**). Failure to properly control a tank's pressure could result in significant financial risk due to lost product and/or catastrophic event, such as a fire or spill.

Tank farm operators commonly have metrics in the following areas, each of which are addressed by proper tank pressure control (**FIG. 3**):

- **Product loss**—Even with depressed oil prices, the approximate value of crude or naphtha can be worth several million dollars for an 80,000-bbl tank. Contamination or spillage of this product would negatively impact a terminal's financial results.
- **Emissions**—From an environmental perspective, tank farm operators need to minimize emissions and corresponding risks to the general public. The U.S. EPA levied more than $470 MM in penalties related to pollution in 2019, and that amount will only increase over time.[3]
- **Personnel safety**—Tanks present occupational challenges to operators. Inspections and maintenance of devices at the top of the tank present fall hazards for personnel. In addition, personnel may be exposed to vapors vented from the tank.

Multi-level protection. Tanks are typically blanketed (or padded) at a slightly positive pressure with nitrogen. Blanket-

FIG. 1. Hydrocarbon storage tanks are often installed far from a control room, making it difficult to monitor their operation.

ing maintains the purity of the product from contaminants, isolates the tank from atmospheric air and moisture, and maintains oxygen levels low enough to prevent ignition.

Tank blanketing and vapor recovery (de-pad) regulators, pressure/vacuum relief valves (PVRVs) and emergency relief vents should be installed on tanks and used together at staggered setpoints (**FIG. 4**). This will ensure protection from conditions above or below the normal pressure range, either of which could compromise the tank's contents or its physical integrity.

The environment inside a tank can be quite complex, which is not necessarily apparent from the outside. Fixed-roof tanks at a process facility or storage terminal can be filled with a wide range of liquids—from chemicals to finished products to crude oil—and can contain volatile vapors under potentially caustic or hazardous conditions. Therefore, it is best to think of a tank as an ecosystem and not as a collection of individual components.

During normal operation, the vapor space inside a tank may expand or contract due to pumping fluids in or out of the tank, or as ambient temperature changes. These tanks are typically blanketed (or padded) at a slightly positive pressure with an inert gas. Conversely, the tank may also be equipped with de-pad or vapor recovery devices to relieve tank pressure when it reaches the upper end of the operating band.

It is completely normal for tanks to 'breathe' during normal operation, whereby blanketing gas is drawn into the tank and vented out of the vapor space. During breathing and other conditions, the tank blanketing system maintains the tank's pressure within a desired control band to ensure tank integrity and the quality of its contents. Operation of emergency vents should never be considered a normal event since these devices are the tank's last line of defense.

Maintenance of tank pressure is accomplished by regulators, with selection of the correct type a key factor.

Pilot-operated advantages and design recommendations. Pilot-operated regulators are ideal devices for tank blanketing applications. Accuracy is paramount due to the low pressures needed in these applications, and fast speed of response is required to account for pump cycling and changes in temperature. These devices have much tighter control and cycle less frequently than control valves used for the same purpose, making them the right choice in these types of applications.

One of the most important design features of pilot-operated regulators is pressure amplification by the pilot, called 'gain.' This feature amplifies a small change in outlet pressure to a much larger change in the loading pressure of the regulator, which controls its operation. This improved accuracy at low setpoints results in a bonus of using less nitrogen or blanketing gas, making the tank less expensive to operate (**FIG. 5**).

Purge meters are also recommended in tank blanketing systems where the process media is corrosive, volatile or can solidify in the lines. Purging maintains a low flow of blanketing gas through the main and sensing lines to isolate the regulator from the downstream process fluid, enhancing the service life of the materials used in the unit and preventing foreign material from the tank backing up into the lines.

Reactive vs. predictive maintenance. To ensure each tank is operating per design, preventative maintenance and inspections should be performed for tank blanketing regulators and other tank top components

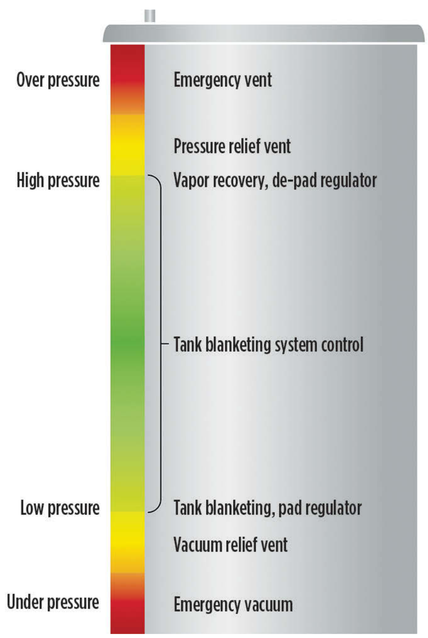

FIG. 2. Several layers of protection are recommended to protect tanks from overpressure and underpressure conditions.

$3 MM+	$470 MM	77%
Potential cost of contamination of 80,000-bbl tank of WTI or naphtha	Judgments and fines levied by EPA for pollution violations in 2019	Bulk terminal locations within 1 mi of communities with 300,000 residents

FIG. 3. Poor control of tank pressure creates multiple risks. Sources: NYMEX spot price, July 2020; U.S. EPA and the U.S. Chemical Safety and Hazard Investigation Board.

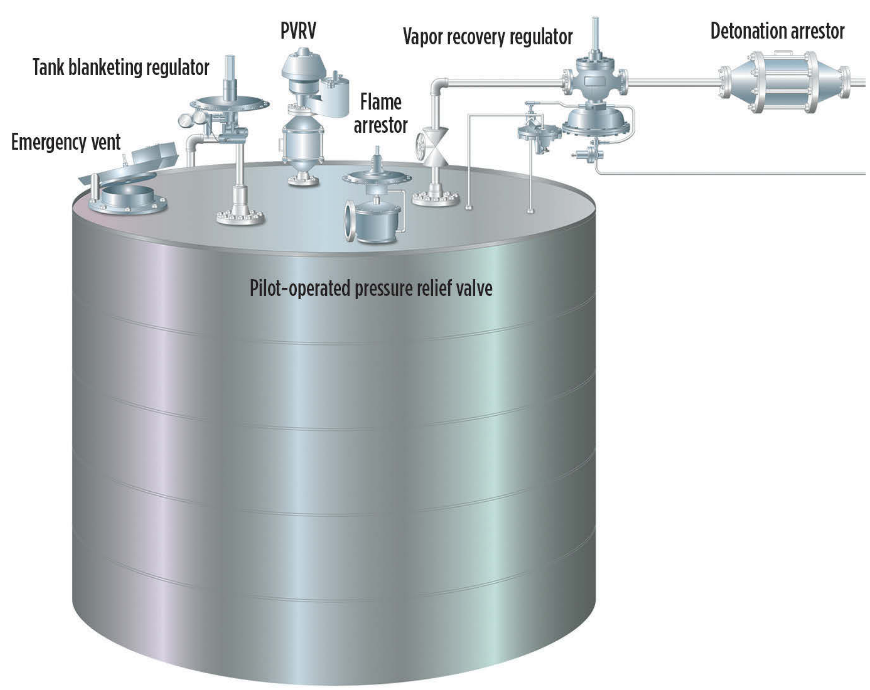

FIG. 4. Full array of devices used together to control pressure of fixed-roof storage tanks.

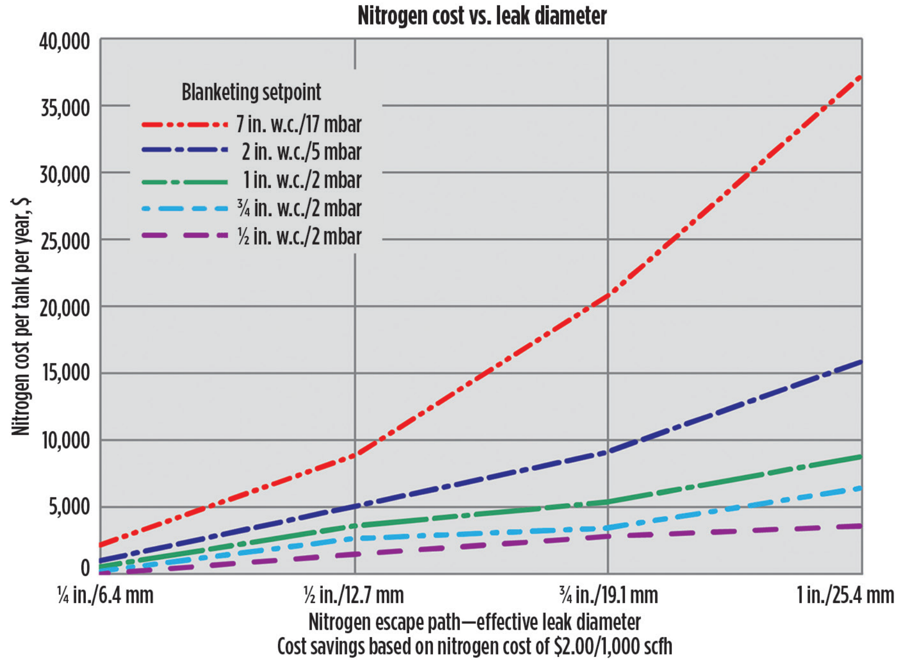

FIG. 5. Tank blanketing regulators sense tank pressure and provide inert blanketing gas at a low setpoint to minimize the amount of gas consumed.

at regular intervals. Maintenance spend is a large percentage of operating costs in any process facility or terminal, but it can be minimized with the right monitoring and control devices and systems.

The goals of any maintenance program are to maintain equipment without excessive cost, while maximizing uptime. Corrective or reactive maintenance costs are often substantially higher than preventative maintenance costs, so the latter method is strongly preferred.

According to an ARC Advisory Group study, the global process industry loses about $20 B due to unscheduled downtime—around 5% of its annual production.[4] Every plant operator can recall several instances where an emergent maintenance item ended up causing significant downtime, but many of these incidents can be avoided with proper care and attention, facilitated by careful device selection.

Proper product design leads to improved maintenance practices related to tank devices. Some pressure regulators on the market can be installed 'at-grade,' meaning they can be set up, checked and calibrated from the ground. This makes maintenance much easier, quicker and safer because technicians can work with their feet on solid ground. To determine if this is a possibility, plant personnel must analyze the specific system and process conditions for the tank blanketing regulators under consideration, often with assistance from vendors.

To provide remote visibility to control room personnel, many pressure control devices available are wireless-ready, and they can be used to remotely monitor various parameters in the tank or its support systems. Although each of these devices could be monitored via traditional wired means, this is often cost prohibitive due to the difficulty of installing wired infrastructure from tanks back to the control room.

Wireless devices can be added to tank vents and regulators to indicate position. Information collected from such an installation helps determine baseline operation of regulators and vents, indicates if both devices are open at the same time (which should not be the case), shows if a vent fails to reseat and alerts if an emergency vent were to open.

Many of these status readings are useful as leading indicators for whether maintenance or inspections should be scheduled for later work or must be performed immediately. With respect to vent monitoring, wireless devices also help plants compile an auditable record to present to government regulators regarding emissions.

Regulators in action. Utilizing tank blanketing regulators as part of a complete tank pressure control system yields financial benefits due to improved operations while minimizing risk. Several vendors offer tank walkdowns to provide a review of tank pressure control devices. Walkdowns can be as narrow or broad as desired, but typically include a review of each tank's physical condition, operability and sizing.

During a tank survey of 40 tanks at a U.S. Gulf Coast chemical plant, plant personnel needed a focused analysis of the costs used for nitrogen blanketing, which were higher than expected. Upon review, it was found that the setpoints of tank blanketing regulators and PVRVs were too close together on several of their tanks.

As a result, the two devices were occasionally open at the same time, thus venting excess nitrogen into the atmosphere during normal operations. By implementing recommendations to adjust the setpoints of their devices, as well as by installing pilot-operated tank blanketing regulators to maintain lower blanketing pressures in the tank, the plant saved more than $500,000/yr in nitrogen costs and reduced emissions.

Takeaway. Fixed-roof storage tanks present various challenges to operators, many of which can be mitigated with a well-designed tank blanketing system. Tanks may often be overlooked at industrial facilities, but technology exists in the market to provide complete pressure control, along with visibility of tank pressure control system operation.

Tank blanketing and vapor-recovery regulators are only a part of a complete system to control the complex tank ecosystem. These devices—along with vent valves, hatches, overfill protection device and others—provide operators with the reliability they need to properly operate and maintain these assets, while minimizing risks to personnel, equipment, the environment and the community. HP

LITERATURE CITED

Complete Literature Cited available online at www.HydrocarbonProcessing.com.

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TOTAL refineries improve overhead systems corrosion and salting with amine-neutralizing technology

Weak organic amines are commonly used in crude unit overhead systems to prevent acidic corrosion from chlorides and other acidic contaminants via a neutralization reaction. While using commodity amines, some refineries experience salt-induced fouling and corrosion issues, which may prompt them to move to non-salting, lower strength amines. TOTAL decided to test this approach to improve reliability for its overhead systems in crude units. This was done through partnership with an industry-leading water technology and process provider[a] to use their proprietary amine-neutralizing technology[b]. This technology is based on a set of principles surrounding the blending of a variety of targeted amines to achieve a balanced neutralization profile, which minimizes salting potential for a given operating envelope. This article describes the route used by TOTAL and the service provider to develop individualized selection and implementation programs for two of their crude units. Each program was based on comprehensive analysis used to choose the best product, define the specific application strategy and define the subsequent benefits of the program changes, according to unit characteristics.

Purpose. The neutralizers are designed to improve both pH control and chloride salt precipitation potential in overhead systems vs. classical amine neutralizer programs. The unique properties of the amine strength and favorable water/hydrocarbon partitioning reinforces these abilities.

The following studies were driven by TOTAL and the service provider to validate amine speciation results between water and hydrocarbon flows over time in two of TOTAL's European refineries. Results from the studies reveal the complex partitioning and recycle behaviors by which these products work and show how detailed water analysis helps to achieve optimization of both neutralizer consumption and corrosion mitigation. The benefits of the analytical campaigns and the overall knowledge of amine behaviors were not possible without a wide collaboration and involvement of all TOTAL teams in developing a systematic and exhaustive monitoring program around the overhead system.

Part of a modern overhead corrosion control program calls for the speciation of amines in a wider variety of flows and computation of detailed salt point calculations on a more frequent basis than are traditionally performed. The advantage is that a refinery can know in a much more granular fashion the precise amount of amine in the overhead circuit and surrounding flows and how they change over time. This allows better control and understanding of the prevailing salt point, which changes over time and is influenced by many complex, dynamic factors that are linked with operations and crude diet. In such a program, amine salt point calculations should not be based on the rate of amine injected into the overhead vapor line, but should be based on the measured amount of amine present in the overhead system receiver at a given time.

Such a program can be important for optimal results because the concentration of amines in the system—and the prevailing salt points that depend on them—is key to ensuring that the transition to a neutralizer will benefit the refinery in terms of its overall corrosion treatment cost.

For both the initiation and ongoing control of the new programs, it was decided that both TOTAL and the service provider would work together to optimize the balance between ongoing neutralization needs and salt point deposition constraints and to then quantitatively validate the specific benefits gained by crude units adopting the new programs.

Amine properties. Commodity amines have been used for decades to protect overhead condensing systems in both atmospheric and vacuum fractionation units. One of the foremost challenges toward the control of corrosion rates in overhead systems is avoiding deposition due to amine hydrochloride neutralization salts.

Traditional primary amines, like monoethanolamine (MEA) and methoxypropylamine (MOPA), have a high polarity and relatively large base strengths (pKa), causing them to react readily with acidic species at relatively low injection rates. However, these same properties also make it difficult to control pH in the typical target range of 5.5–6.5 (blue line in **FIG. 1**). In addition, the neutralization salts formed have higher than desired salt point temperatures that increase the potential for salt-induced corrosion and fouling.

Conversely, the neutralizers used in this study are generally composed of blends of both secondary and tertiary amines. As

such, they have a lower polarity and smaller base strength than classical amines. This results in better controllability within the target pH range (red line in **FIG. 1**), as well as neutralization salts characterized by lower salt point temperatures and improved tendencies for salt formation downstream of water condensation to better avoid salt laydown. Using a mix of amines also decreases relevant partial pressures, which lower salt deposition risk. While these same properties might, at first, lead to the expectation of higher injection rates needed to elevate the pH to target, in practice, additional complex behaviors cause the amines in these blends to significantly partition to oil phases in a beneficial and targeted way when oil and water mix under typical operating conditions. As this article will examine, this phenomenon significantly reduces practical injection rate requirements and makes these programs cost effective, with better controllability and salt property benefits.

The partitioning effect outlined is highly pH dependent and is unique for each amine species used in an amine neutralizing product. This strongly impacts the amount of amine in both the hydrocarbon phase of the overhead circuit and in the desalter through the addition of desalter wash water returned from topping.

FIG. 2 shows theoretical partitioning curves for three amines used in the service provider's neutralizer programs outlined here. It shows that some amines start to partition to the hydrocarbon as pH rises above 8, while others can start partitioning as pH rises above 5. Traditional primary amines generally have effectively no hydrocarbon partitioning potential in the range of desired boot water (BW) pH control. This property was confirmed by the detailed analytical plan developed in cooperation between TOTAL and the service provider.

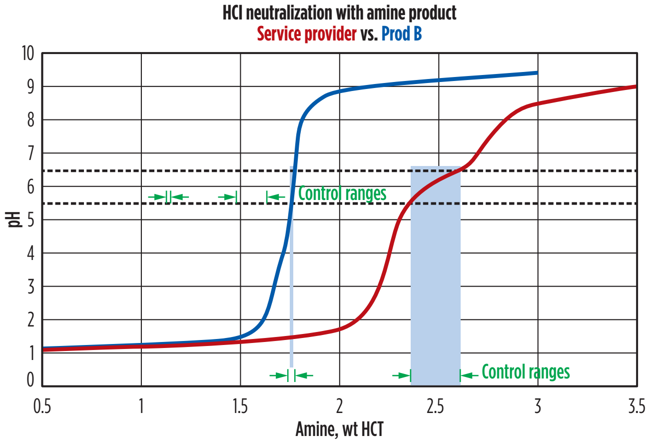

FIG. 1. Comparative neutralization strength and needs.

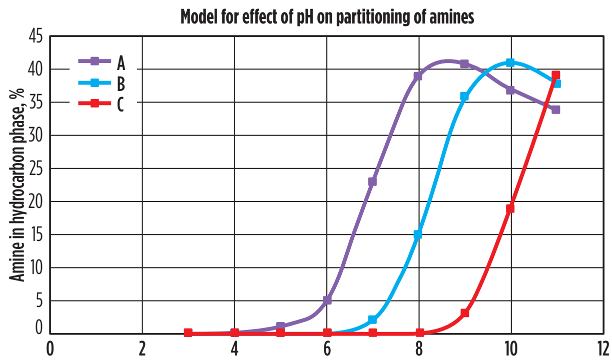

FIG. 2. Effect of pH on amine partitioning in hydrocarbon phase.

Amine partitioning can cause amines to recirculate when water containing amines is contacted with a hydrocarbon stream, which will be reinjected to the column through the desalter. These recycle contributions can result in higher levels of amines in the overhead line than would be expected based only on the mass flowrate of amines injected in the overhead vapor line as a neutralizer. Due to a low salt point temperature, it has no expected impact in the column, as it is important to avoid any salt-induced corrosion in the lower side draw of the crude unit.

Amine analysis in the different streams of a crude unit can be very important and will lead to a better knowledge of concentrations for various amines inside the tower and the overhead system. This is important because the information can be used to better monitor real-time amine salt points and practical corrosion control tactics. This is especially true for the amines, where, due to the partitioning and recycle phenomenon previously described, simple mass balance calculations tend to overestimate the amount of neutralizer required to meet ongoing demand.

Analytical plan. The service provider developed a new method for amine speciation in overhead water sample by ion chromatography mass spectrometry (IC-MS), with a detection limit as low as 0.1 ppm for each amine and that avoids the interferences and coelution issues usually seen between amines of the same family (**FIG. 3**). Comprehensive and detailed amine analysis using this method is economical, precise, accurate and make the analysis of a wide variety of key amines available in overhead water samples.

Conversely, for hydrocarbon samples, it is necessary to first extract the amines from the hydrocarbon phase with acidified water. This works well for light hydrocarbon cuts like naphtha, but reliable results are more difficult in crude oil due to numerous interferences and the potential for column contamination by long eluting compounds. Therefore, the amines in desalted crude oil are calculated by material balance using the wash water and brine, respectively entering and leaving the desalter.

Case 1: Simple crude unit. The first unit where TOTAL and the service provider transitioned to the amine-neutral-

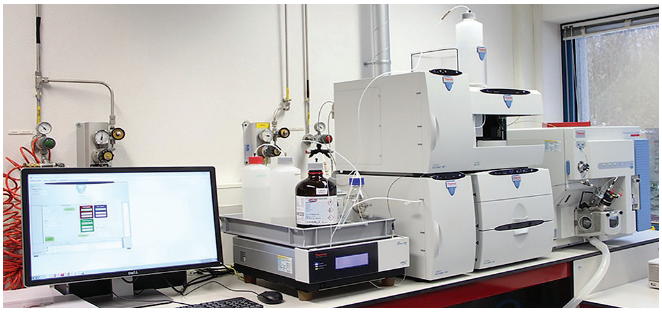

FIG. 3. Amine speciation device.

izing technology is in one of TOTAL's European refineries, where the crude unit contains both a desalter followed directly by a furnace and then a main fractionator (MF). The neutralizer was injected into the MF overhead to control BW pH. As shown in FIG. 4, amine recirculation primarily takes place in two different circuits of the crude unit. These include:

1. In the overhead naphtha reflux
2. With overhead water used as wash water to the desalter and around the desalter.

However, it is important to note that in some refineries, there can be several other significant recirculation routes impacting the prevailing steady-state overhead concentrations, which will not be discussed here.

Using the new method for amine speciation, amines from the program were examined in several streams around the crude unit to determine their respective concentrations in the overhead system, as compared to the injected quantity.

Samples were analyzed by TOTAL and the service provider from the following streams:

- Water samples
  - BW
  - Desalter wash water (WW)
  - Desalter brine (DB)
- Hydrocarbon samples
  - Reflux naphtha (RN).

In addition, amines were calculated for the following streams:

- Crude oil: Calculated by difference (CO = WW – DB)
- Injected neutralizer (IN): Based on injection rate and amine concentration in product.

TOTAL and the service provider agreed to perform a comprehensive set of analysis on a frequent and regular basis to continuously assess the prevailing amine concentration ratio and associated salt points in the overhead because pH dependence and other complex factors can often cause the values to be very dynamical. One example of results—shown in grams of amine—is presented in FIG. 5.

If there were no amine recycle, then the BW analysis would match calculated amines from the IN. However, the measured level of BW amines is 40% higher than that of the IN amines. This demonstrates that there is significant amine recycle; therefore, calculations for salt point temperatures based on injected amine quantity will result in salt point temperatures that are lower than actual. When controlling tower operations to maintain a certain safety factor surrounding salt deposition, the difference between amine-partial pressures assumed to be derived from amine "as injected" and the partial pressures computed based on actual measured circulating amine can result in unexpected issues with salt-induced corrosion and fouling. The additional streams shown in FIG. 5 were then examined to determine the source of the amine recycle and close the mass balance. No amine was detected in the RN, as expected, due to a pH of around 6 in the BW. To restate, the amines in the DB were subtracted from those contained in the desalter WW to calculate the amines in the crude oil. As the desalter operates at a pH of about 8, as directionally expected from FIG. 1, the data treatment indicated that more than 50% of total amines were entrained with desalted crude oil.

The quantity of amines entrained in the desalted crude oil, combined with those injected into the overhead system IN, agrees with the amount analyzed in the BW, with a 2% difference, which is quite good.

To better illustrate the typical propagated error expected between these two methods, salt points are compared. These were obtained first by once-through mass balance calculations based on amine injection rate (IN) and then by computing them using the measured BW concentrations.

As shown in FIG. 6, the difference in computed salt points for the two methods is 3.6°C, which is significant. This difference would be especially important regarding the mitigation of corrosion in cases where the salt point and the water dewpoint are close to one another. In such cases, the evaluation of amine recycle factors would be necessary to accurately evaluate system salt points. The overall concentration ratio factor for amines in this overhead system (BW/IN) was shown to be 1.4 in FIG. 5.

This exercise was conducted on a regular basis and confirmed over time that the BW/IN ratio varied between 1.1 and 1.4, mainly as a function of desalter pH and unit oper-

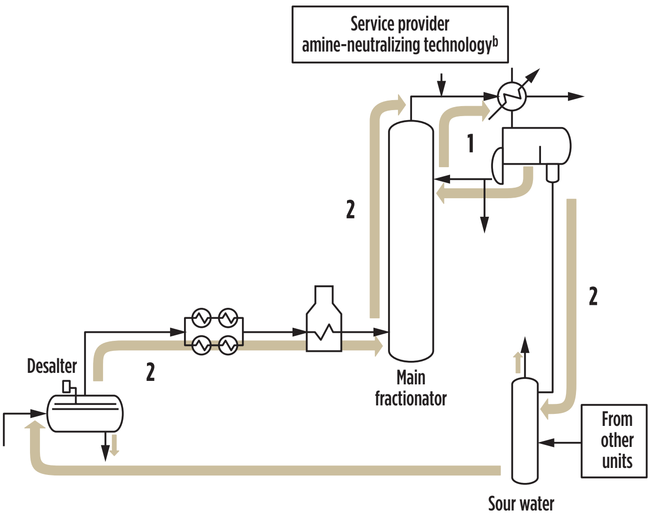

FIG. 4. Amine recycle paths.

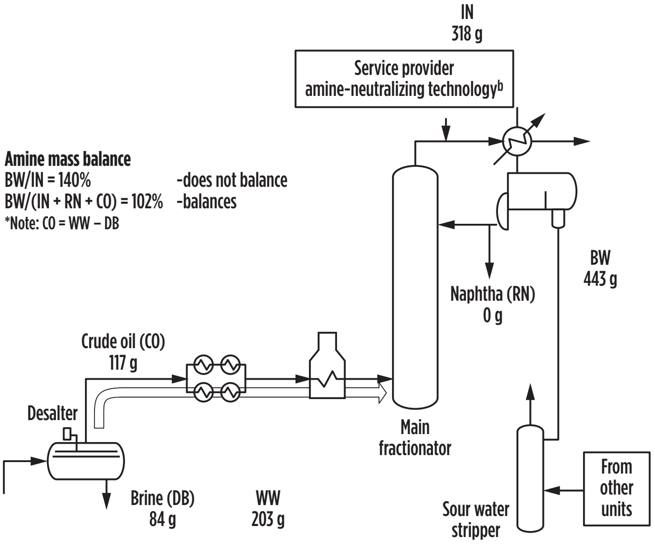

FIG. 5. Analytical results.

ating conditions. It also confirmed that the neutralizer is always present in the atmospheric tower through desalter recycling. Defining a standard recycle ratio (BW/IN) is needed to properly and practically evaluate daily salt points based on the amine injection rate. This is especially important because the amine speciation methodology requires time to obtain results subsequently used to perform the amine balance. To have enough safety margin, TOTAL and the service provider agreed to use an ongoing recycle ratio of 1.5 and calculate, on a daily basis, the amine salt point based on both the injected amount only and then a second salt point based on amine expected by including the recycle factor of 1.5.

Because of the recycle ratio factor and its impact on salt point computation, it is important to choose the right neutralizing amine and to exploit its recycle behavior to ensure that no salt fouling and associated corrosion occurs in the tower or in the overhead condenser system.

A second benefit from the recycle factor is the global injection rate of the amine-neutralizing programs, which is very often less than when using classical amines at a constant pH target range; therefore, reducing treatment program costs, while maintaining the benefits of better corrosion control and system performance. In this case, when moving from a commodity amine to a neutralizing amine, the injection rate based on the use of a lower neutralizer strength amine (**FIG. 1**) was

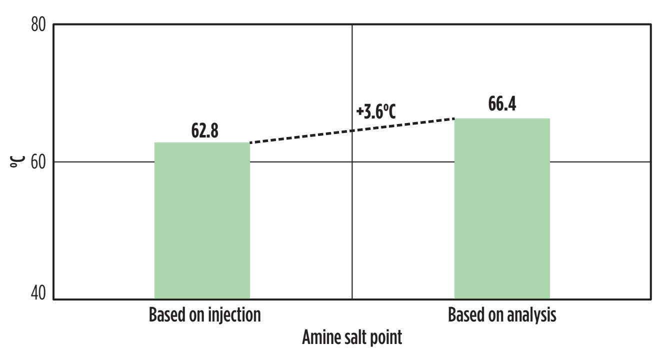

FIG. 6. Salt point temperatures.

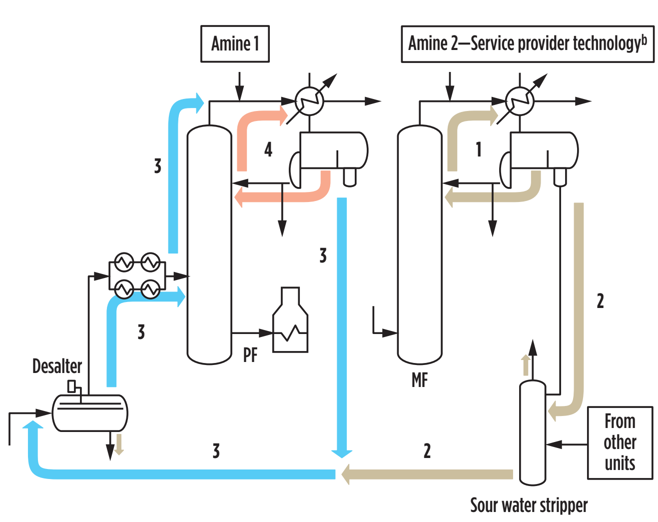

FIG. 7. Recirculation of service provider amine in a PF column.

proposed to be 20% higher. However, due to the recycling advantage of the amine, the actual injection rate represents about 80% of the previous injection rate, which confirmed this program to be very cost effective.

Case 2: Crude unit with preflash (PF). After this first success, TOTAL and the service provider decided to apply the same technology and approach in a more complex unit with a PF column upstream from the furnace and the MF column. The behavior of amines injected into the overhead of both the PF and the MF is different than in the case previously presented, with a more complex recycle scenario. Because of the different configuration of the unit, it was decided to once again implement a similar type of analytical plan to evaluate the recycling effect and its consequences, with respect to computed salt deposition potentials before adopting the amine-neutralizing program.

This was critical because overhead water acidity is a key driver of amine selection. Light organic acids (e.g., acetic acid) are more likely to condense in the overhead of a PF than in the downstream fractionator overhead. This behavior can then drive a higher neutralization demand. This is true even in the absence of problematical chloride levels. Conversely, chlorides are more likely to condense in the overhead of a MF because hydrolyzing chlorides from mineral salts in crude oil need the additional time and temperature provided by passage through the crude furnace.

As represented in **FIG. 7,** when Amine 2 is injected into the overhead of the MF, it can recycle with BW through the desalter as wash water and route to the PF overhead system rather than to the MF one where it was originally injected.

Similarly, Amine 1 injected into the overhead of the PF recycles through the PF overhead but does not end up in the MF overhead. Unlike Case 1, this causes preferential cycle-up of oil soluble amines in the PF but not generally in the MF. This difference—caused by recycle loop behavior—should drive program design with the goal to manage salt points in both overheads simultaneously. To achieve these goals, granular and frequent amine speciation with following salt point calculations are of prime importance.

By using an amine-neutralizing product[b] (Amine 2 in the MF overhead **FIG. 7**), operators can manage salt points in the MF overhead and it plays a role in PF overhead pH control through recycling. Recycling reduces the required injection rate of Amine 1 in the overhead of the PF (even possibly down to 0 in certain operating cases). It also allows the use of a classical primary amine because fewer condensed salts are expected due to overall lower hydrochloric acid condensation. This behavior depends on the bottom temperature of the PF column and on the amine boiling point.

TOTAL and the service provider decided to adopt a similar analytical plan as used in Case 1 to evaluate the recycle of amines for Case 2. The following streams were sampled with the same type of analysis as before:

- Water samples
  - MF BW
  - PF BW
  - Desalter WW
  - Desalter effluent

- Hydrocarbon samples
  - MF RN
  - PF RN.

Two different neutralizer products were chosen for the two injection points. These included:

- The neutralizer (Amine 2 in **FIG. 7**) for the MF overhead system and chosen to avoid any salt deposition there by chloride ranging between 5 ppm–20 ppm
- A MEA-based neutralizer in the PF overhead (Amine 1 in **FIG. 7**) and chosen because chloride levels were consistently below 1 ppm, so salt precipitation was unlikely.

First, no amine was analyzed in the NR of both the PF and the MF. This confirmed what was analyzed in Case 1: a BW pH range of 5.5–6.5 prevents amines to be recycled with NR. It was reinforced by a pH target in PF in the range of 5.5–6 as acidity is more expected to be organic than chlorhydric. The pH and the choice of a conventional primary amine, which has more affinity with water, explains why there is no recycling of Amine 1 injected in PF via the desalter. The second confirmation is that the Amine 2 injected in the MF overhead was recycled into the PF. The data showed that approximately 30% of neutralizing amine injected into the MF was recycled into the PF (**FIG. 8**), with the variation driven primarily by changes in the desalter pH. This phenomenon helped to reduce the Amine 1 injection rate to a minimum level, which greatly reduced the risk for salt deposition, while effectively protecting against dewpoint acid attack.

This second case confirmed the ability of the amine-neutralizing solution to recycle in the system and to reinforce corrosion protection, while reducing salt precipitation risk. At the end, there was no more risk of salt precipitation in the MF, and neutralization needs were reduced in the PF. This situation enabled TOTAL to better mitigate corrosion in both columns without additional costs.

Takeaways. The amine-neutralizing technology can be a very cost-effective program compared with classical neutralizing amine treatments. As this article has shown, this is due to the complexities involved with the use of secondary and tertiary amines, which show pH-dependent partitioning and recycle behavior vs. traditional primary amines. The large economic and reliability benefits imparted by using such amines typically justify the extra complexity and attention needed to control and optimize them.

The ability for the amines to partition strongly into hydrocarbons and concentrate in the overhead system helps to reduce neutralizing injection and chemical needs, while also reducing detrimental pH fluctuations and salt precipitation tendencies. When corrosion is not optimally mitigated, it can often result in loss of production and increased maintenance cost, which greatly increases total cost of ownership. If used properly and considering the total costs of overhead corrosion over time, the neutralizers can represent an optimal choice.

In summary, the amines helped TOTAL to better control pH, with minimal risk of salt deposition. Partitioning and recycle advantages illustrated in these two case studies allow these amines, in these two cases, to:

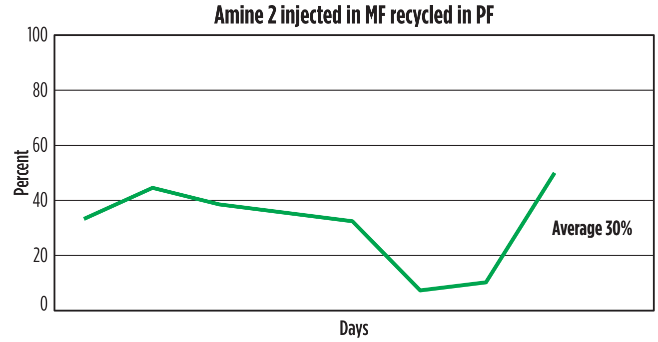

FIG. 8. Amine 2 recycled in PF.

- Concentrate in overhead of the atmospheric column with a typical recycle ratio of 1.4, used to calculate a more representative salt point in the overhead system with reduced global neutralizer demand
- Recycle 30% of amine injected in a MF to a PF overhead to eliminate amine salt deposition in the MF overhead system, while reducing injection needs in PF.

Both the corrosion control program and the study were very successful towards maximizing corrosion mitigation, with minimal risk of salt deposition in both affected units. Thanks to the detailed ongoing analytical plan that was adopted, TOTAL and the service provider were able to document the improved corrosion control, salt deposition potential and chemicals costs. This work also helped to develop a more structured approach to implementing an overhead neutralizer program using the amine-neutralizing technology that considers the variation in crude unit design and its operations over time. HP

NOTES

[a] SUEZ – Water Technologies & Solutions
[b] Refers to SUEZ's LoSALT technology

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HP | Maintenance and Reliability

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Improve the reliability of a CO_2 compressor in a urea synthesis/granulation plant

The carbon dioxide (CO_2) compressor is one of the key major equipment in a urea production plant that produces fertilizers. The compressor is normally a between-bearings, single-shaft centrifugal compressor design based on API 617.[1] Without the compressor, plant production would be stopped. **FIG. 1** shows a typical CO_2 compression process in a urea plant, including a steam turbine, low-pressure casing, gearbox and high-pressure casing with suction knockout drum, inter-stages piping, coolers, reactor and separators.

The production cost of a urea plant producing fertilizer can be optimized by maximizing the compression system operation time, reducing unplanned shutdowns and keeping operating costs to a minimum under operational conditions. The CO_2 compressor is the heart of the urea plant's synthesis process and its performance and reliability will impact the overall plant operating cost, availability and reliability.

This article addresses parameters that impact the performance and reliability of the CO_2 compressor, based on the author's past experience working in large-scale ammonia and urea production plants.

Compressor type selection. Depending on plant production capacity and the licensor's past experience, both single-shaft, between-bearings compressors or integrally geared compressors are possible options. However, single-shaft, between-bearings centrifugal compressors are normally selected by many licensors and are recommended by the author because:

- The number of bearings and shafts are higher than the single-shaft compressor
- Integrally geared compressors impellers run at different speeds
- Integrally geared compressors impellers run at higher speeds than the single-shaft compressor
- Integrally geared compressors are normally a package design, which limits ease and safe access for operation and maintenance
- The number of dry gas seal cartridges is higher than the single-shaft compressor
- They are more susceptible to vibration compared to single-shaft compressors due to the overhung design of the impeller and a higher shaft and impeller velocity
- Their efficiency is lower than a single-shaft compressor
- Their height is normally higher than a single-shaft compressor
- Integrally geared compressors need an internal guide valve (IGV)
- Single-shaft compressors can be direct driven with a steam turbine.

However, a detailed study is required, and other factors such as the vendor's experience, power, efficiency, etc., should be considered when selecting the compressor type.

Material selection. CO_2 corrosion results when CO_2 gas dissolves in water, liquid or process condensate to form carbonic acid [(H_2CO_3) siderite], especially with higher pressure. This type of corrosion can happen either during normal operating conditions or when the compressor is in standby and under pressure. Material selection is the key activity of the compressor, upstream equipment/piping, downstream equipment, piping and instrumentations.

Note: It is highly recommended to use the API 617 format datasheet and clearly mention the gas composition, hydrogen content, liquid content, water content, etc.

Increasing the level of chromium in the wetted steels offers no major improvement in resistance until a minimum of 12% is reached.[2] Critical factors that impact CO_2

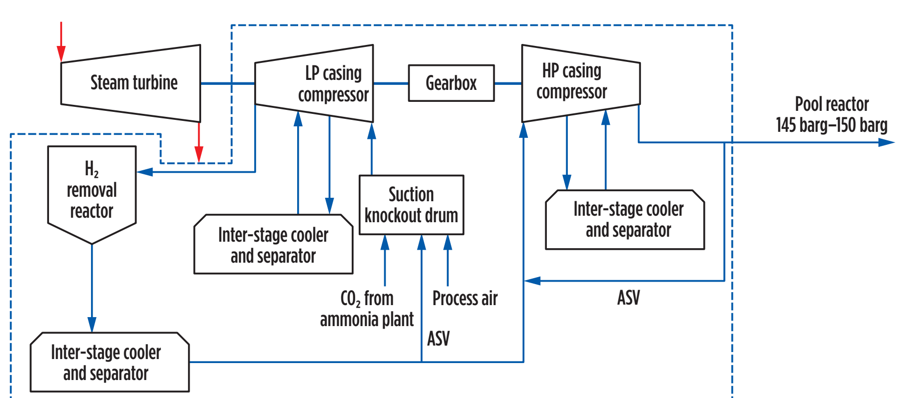

FIG. 1. Simplified process for CO_2 compression in a urea plant. The dotted line shows the boundary of CO_2-wetted, stainless-steel wetted material.

corrosion rates include CO_2 partial pressure, pH, gas velocity and temperature.

CO_2 compressors are unique in terms of material selection. All wetted metallic material and parts with CO_2 gas in a compressor (i.e., casing, inlet guide valves, diaphragms, impellers, shafts), upstream piping material, upstream equipment, inter-stage piping material, inter-stage equipment, metallic gaskets and instrumentations should be stainless steel, except for labyrinths, shown in **FIG. 1.**

This requirement will impact the compressor's CAPEX, so vendors or engineering companies sometimes do not use stainless-steel material for the wetted metallic parts, which can cause major difficulties for the end user. It is highly recommended to add stainless material for the wetted parts in the API 617 datasheet in case the gas nature is wet or a possibility exists of wet gas during operation or standby condition under pressure.

If cost constraints are a factor and the intention is to use carbon steel material (which the author does not recommend for wet gas services), cost-effective options to mitigate the risk of CO_2 corrosion include:

- Applying electro-less nickel plating on the wetted carbon-steel material
- Using stainless-steel cladding on the wetted carbon steel material
- Evaluating where a CO_2 gas condition may change to wet gas inside the compressor in each stage (i.e., impeller, diaphragm, diffuser and casing) and checking the gas condition at any temperature and stage above its water dewpoint during compressor operation or standby under pressure. Note that the variation in gas composition can change the water dewpoint of the gas.

FIG. 2 shows examples of severe CO_2 corrosion in a CO_2 compressor with carbon-steel, stationary wetted material.

Process air. Process air is added to the CO_2 stream in ammonia and urea plants for the following main reasons:

- As combustion air for hydrogen (H_2) removal from CO_2 in an H_2 removal reactor
- As an anti-corrosion agent for the synthesis equipment—the oxygen in the air keeps the synthesis equipment passive for corrosion.

Cleanliness and dryness of the process air supply plays an important role in the reliability and performance of the CO_2 compressor. Proper sizing of the strainer and separator close to the tie point must be considered for the process air. Careful de-watering, flushing, drying and commissioning of the process air piping should be considered.

Knockout drum. Liquid in the gas stream is generally harmful to any compressor and should be avoided by proper inlet system design. Where risk of liquids is present, compressor inlet and inter-stages should be provided with properly sized liquid separators or knockout drums. The location, orientation and elevation of the gas inlet and outlet nozzles in the separator should be carefully placed to prevent risk of liquid carryover to outlet gas toward the compressor inlet. In addition, if the separators are furnished with process condensate pumps for drainage and the minimum flow lines of those pumps are connected to the separators, the connection point will be in proper orientation and elevation to prevent liquid carryover or liquid spray in the flowing gas.

Level transmitters, level indicators and level switches are necessary to monitor and control the liquid level in the knockout drums and the separators. It is recommended to validate their operation daily and confirm their nozzle elevation and location in the vessels before initial field calibration. The use of high-efficiency demister pads and internals are necessary to prevent liquid from migrating to the

FIG. 2. Severe CO_2 corrosion of carbon-steel casing.

outside of the vessel with the gas. Note: no internal/demister pad to scrubber, separator or knockout drum has the ability to remove 100% of the liquid from the gas.

CO_2 compressor location in fertilizer production. Each ammonia and urea plant (fertilizer) has five main compressors, shown in **FIG. 3.** The CO_2 compressor can be located in the same building as the other four compressors in the ammonia plant, or it can be located separately in the urea building—sometimes called the urea tower—at the urea plant. Installing the CO_2 compressor in the urea plant will cost less than in the ammonia plant, creates more operational flexibility and is better from a safety perspective during outages, operation and maintenance work.

Insulation. Insulating [sometimes with electric heat tracing (EHT)] the compressor, piping, and upstream and interstages piping and equipment is necessary. Reasons for insulating the compressor inlet and discharge piping include:

- Noise attenuation
- Preventing atmospheric condensation and icing on the pipe surfaces, with heat tracing
- Preventing water and hydrocarbon condensation when the ambient temperature is cooler than the gas temperature in the inlet line to each stage
- Personnel protection when the surface temperature is > 60°C.

It is recommended to occasionally check the insulation material for contami-

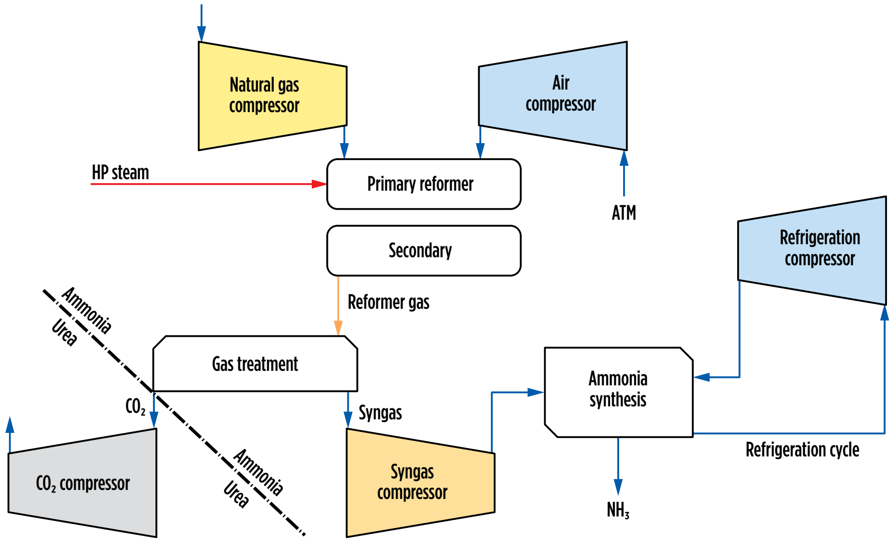

FIG. 3. Compressors used in an ammonia and urea plant.

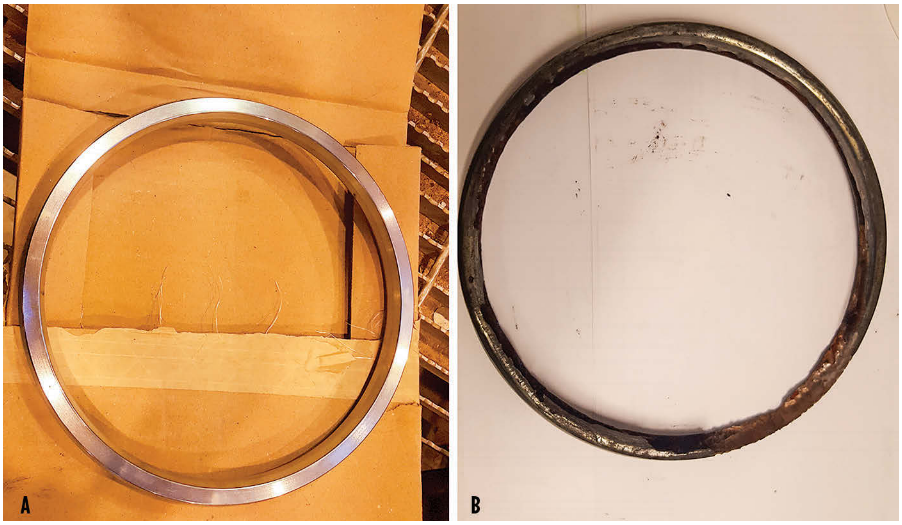

FIG. 4. A new CS RT gasket (A), and a corroded CS RT gasket after 2,000 hr (B).

nation. Insulation material on austenitic stainless-steel equipment should be analyzed for chlorides, while insulation material on carbon steel should be analyzed for nitrates due to the risk of external stress corrosion cracking. Do not forget to reinstall insulation completely after turnaround, outage, maintenance and inspection of the compression unit.

Liquid trap. Adding a liquid trap at the inlet piping of a compressor is highly recommended, as is the regular examination of leakage and operation of the traps.

Moisture sensor/dewpoint sensor. The addition of a moisture sensor in the inlet piping to the compressor is recommended, particularly when carbon material is selected.

Dry gas seal. A risk of suffocation exists when gas escapes through a leak. Sometimes, a labyrinth seal with nitrogen purge gas or carbon ring are used as a last line of defense at the compressor casing to seal the shaft. However, as the compressor is normally located inside the building, it is recommended to use a dry gas seal when technically and economically possible. If the hydrogen content is high and/or the operation is a high-pressure application (e.g., high-pressure casing), a tandem dry gas seal is highly recommended.

FIG. 5. Corrosion and erosion on the gas passage will cause local stalling in a compressor.

FIG. 6. Corrosion products and scale on the return wall of a CO_2 compressor (A), and catalyst carryover entering the compressor (B).

Piping gaskets. Normally, ring-type joint (RT) gaskets are used between piping and compressor flanges. RT gaskets have a lower gas leakage rate compared to spiral wound gaskets. However, if the flange bolts are overtightened, the gasket may damage the flange grooves and cause CO_2 gas leakage. Repairing grooves in an installed condition may not be possible and may require flange replacement.

As all wetted piping and equipment in the compression system are stainless steel, gaskets should be stainless steel, as well. Using carbon steel material for the gasket carries the risk of galvanic corrosion and can result in gas leakage. Additionally, carbon steel, RT joint gaskets can easily be corroded if liquid, water or process condensate comes in contact with CO_2 gas. For galvanic corrosion to occur, three elements are required:

- Two metals with different corrosion potentials
- Direct metal-to-metal electrical contact
- A conductive electrolyte solution (e.g., water).

In addition to these three elements, the relative surface area (not mass) of the exposed metals is also an important factor. If the area of the cathode (noble metal, here stainless-steel piping and flange) is very large, and the anode (active metal, here carbon steel material) is very small, the current produced is likely to be very high and the anode (i.e, carbon steel RT gasket) will corrode quickly. **FIG. 4A** shows a new carbon steel RT gasket installed between stainless-steel flanges, and **FIG. 4B** shows that same carbon steel gasket corroded after less than 2,000 hr in service with CO_2 gas and process condensate.

Inlet pipe to compressor. Inlet piping to each stage of the compressor should be designed for ease of cleaning and inspection. Inlet piping from below the compressor casing is recommended with the provision for insertion and removal of temporary strainers close to the compressor inlet without upsetting compressor alignment. A T-type welded strainer is highly recommended compared to cone or Y-type strain-

ers, especially for sizes greater than 10 in. Clearances between the strainer element outer surface and the pipe internal surface should be minimized to mitigate the risk of particle bypassing the strainer element. Note: A temperature gauge or transmitter should not be installed downstream of the strainer. All instrumentation wells should also be stainless steel. It is highly recommended to validate any stainless-steel material before installation by portable positive material identification tolls.

Catalyst carryover. Normally, the hydrogen content downstream of the H_2 removal reactor should be less than 10 ppm. Corrosion products will impact catalyst performance. The catalyst in the H_2 removal reactor normally consists of platinum on an aluminum oxide carrier. Low catalyst activity may be the result of catalyst poisoning, such as corrosion products, due to using carbon steel material for the compressor casing.

An additional risk exists of catalyst carryover with CO_2 gas and a return to the LP casing via an anti-surge valve (ASV) (**FIG. 1**). Provisions for preventing catalyst carryover and entering the compressor must be carefully considered in the design of equipment downstream of the H_2 removal reactor. Do not install the piping downstream of the ASV to the compressor inlet. It should be installed upstream of the compressor knockout drum.

Diaphragm and casing material. The use of stainless-steel series 300 or 400 casing and diaphragm material are recommended. Using a stainless-steel diaphragm with carbon steel casing material presents the risk of galvanic corrosion. Forged material is recommended compared to plate material for the diaphragm. It is highly recommended to perform wet magnetic particles for diaphragms during compressor overhaul. Provisions should be made for the easy and safe removal of the stainless-steel diaphragm. During overhaul, all galleries, gas passages/diffusers, casing internal surfaces, etc., should be carefully inspected using the proper tools and nondestructive examination.

Condition monitoring. In addition to online shaft probe vibration monitoring, it is recommended to regularly check the bearing housings vibration with an appropriate portable vibration analyzer. Sometimes, the shaft vibration probes indicate no abnormal vibration as they measure shaft displacement compared to the bearing housing; however, the bearing housing has high vibration due to gas flow inside the gas channels/diffusers, reflecting the vibration to the bearing housings. Corrosion of the gas passages may cause stalling even if the compressor is running at a high flowrate.

Stall is a local disruption of the gas flow inside the compressor due to gas velocity direction change. For an early detection of this issue through vibration, regular monitoring is recommended. Small amplitude deviations or spikes in a broad low-frequency range of the vibration spectrum [fast Fourier transform (FFT)] may be due to a stall happening inside the compressor stage (**FIG. 5**).

FIG. 7. Siderite ($FeCO_3$) is the corrosion product of carbon steel in a CO_2 environment.

Performance monitoring. CO_2 compressor performance will be impacted due to CO_2 corrosion of diffusers, inlet guide valve, diaphragm, impeller, etc., and clearances of the labyrinth. The consequences of these processes range from the plugging of the diffuser channel with catalyst particles and/or corrosion products, to physical damage to the impeller, shaft and stationary parts (**FIG. 6**).

In addition, carryover of the particles and deposits of siderite ($FeCO_3$)—the corrosion product of carbon steel in a CO_2 environment with high-velocity gas—can easily damage the impeller, shaft and other compressor parts in the path of gas (**FIG. 7**).

By monitoring the compressor's performance and identifying any deviation in polytrophic head or polytrophic efficiency, operators can identify problems inside the compressor that may not be identified by condition monitoring, such as vibration monitoring.

Takeaway. A CO_2 compressor is a single machine without hot standby in a urea plant. A minimum of 1 wk is normally required for field disassembly and re-assembly of a two-casing compressor driven by a special purpose steam turbine, assuming all parts, resources, special tools and experience are available and no major repairs are needed. Such a production stoppage creates a significant cost for the plant owner.

Theoretically, compressor systems are designed to avoid liquid at the compressor suction by removing hydrocarbon condensate or water in scrubbers and sending the dry gas in thermal insulated lines, when possible. However, in reality, liquid removal with 100% efficiency is infeasible. The risk of corrosion inside the compressor must be studied during detailed design. Performance and condition monitoring should be considered. Stainless-steel series 300 is recommended for all wetting parts with CO_2 gas for compressors, upstream piping material/equipment/instrumentation, inter-stage equipment, piping material and instrumentation. HP

NOTES

The recommendations outlined in this article are based on the author's experience and are not related to any company.

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Alarm management: A pillar of process safety management

The following describes how an adequate implementation of alarm management is a fundamental part in process safety management (PSM). Since alarm management is one of the best strategies for diagnosing, evaluating, improving and controlling the performance of the various processes involved in the hydrocarbon processing industry, this strategy enables personnel to structure and facilitate the understanding and involvement of staff with the main elements of PSM.

In addition, this article details how concepts, stages, indicators, etc., of alarm management are compatible with the main elements of PSM, allowing it to be incorporated into this management system.

One of the main challenges for a sustained and successful implementation of PSM is that it remains updated over time and provides timely and correct information about a process' performance, so that its elements allow it to manage the current deviations. This challenge is addressed by the implementation of an adequate and crucial alarm management.

To implement proper alarm management, the following stages should be considered (**FIG. 1**): Diagnostics (from the initial state of the alarm system), analysis (identification of deviations and their sources), implementation (application of improvement actions) and operation (for control and monitoring of the final state).

Developing alarm management. During the development of alarm management, the operational discipline that an organization has developed over time is assessed. During this development, fundamental documents are reviewed that are sometimes not adequately updated or, at least, with the necessary detail or frequency, identify whether control strategies are aligned with current process requirements for safety and productivity, and, above all, identify whether there are properly documented and supported changes or adaptations under the organization's policies and standards. In addition, this is an excellent opportunity to bring together teams from different areas of an organization (e.g., operations, engineering, security and maintenance) to improve operational and safety standards, strengthening teamwork.

Diagnostics. This is the base stage of any alarm management implementation process. Before starting the process, it is advisable to evaluate the following symptoms:

- Control screens are covered by active alarm signals, even under normal operating conditions
- There are active alarms for long periods of time without being attended by the staff in charge
- Massive alarm recognition without analysis or prior investigation (i.e., clean alarms)
- Deactivation of alarms, decrease of the volume of the audible alarm system or modification of alarm values in the system.

If these symptoms occur in a system, it is likely that an alarm management system should be implemented to strengthen the process management system before an unexpected event occurs.

To have an adequate starting point, it is advisable to begin with the review of the philosophy or strategy of control, alarms and automatic interlocks—to have a good understanding of the processes involved and, above all, the level of updating and changes made over time. Typical documents to review at this stage are the control philosophy, facility and process design, operating procedures and cause and effect matrix.

After the process is understood and reviewed, the metrics for the definition of

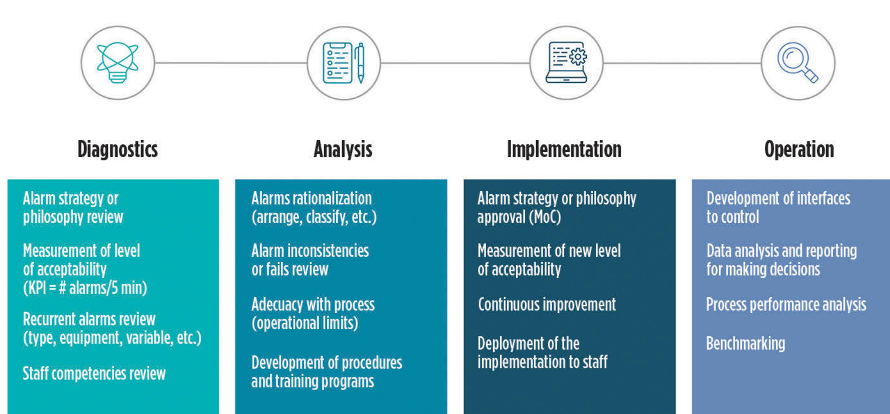

FIG. 1. Stages of development of alarm management.

TABLE 1. Criterion for the acceptability of alarm systems

No alarms recorded in stable operation	Acceptability Section A to D: no additional source
More than 1/min	Unacceptable
1 every 2 min	Over scathing
1 every 5 min	Manageable
< 1 every 10 min	Acceptable

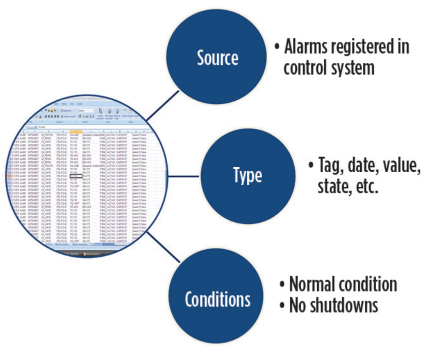

FIG. 2. Getting data considerations.

the level of acceptability are established, which will be the main criterion for the measurement and subsequent control of the alarm management to be implemented. Many ways exist to establish this criteria; however, having a reference based on recognized standards or good practices will provide greater support and a future possibility of reference with other similar processes or plants.

As an appropriate and well-accepted criterion in the industry, the Engineering Equipment and Materials Users Association (EEMUA) 191 standard[1] can be adopted, which sets the level of acceptability depending on the number of alarms recorded under normal conditions (**TABLE 1**).

Depending on the level of acceptability determined during the diagnosis, the goal is to improve the level as implementation progresses, recommending the "manageable level" to be achieved (i.e., one alarm every 5 min).

Control systems usually have functionalities that allow the alarm records to be obtained, which, in turn, are properly organized according to the process variables (flow, pressure, temperature, etc.) to which specific process or equipment are associated, to which signal or controller they belong, and even the type and level of alarms or automatic stop (**FIG. 2**). This makes it easier to manage the information for the analysis stage, allowing personnel to export that information to computer tools such as spreadsheets or databases. To avoid distortions or inaccurate decisions, it is important to consider the following when selecting evaluation periods:

- Information should be taken during periods when the process has developed within normal operation (i.e., without scheduled or unscheduled plant shutdowns)
- Preferably under relevant operating conditions (i.e., processing loads or relevant production levels).

An important part of the diagnosis is the validation of staff competencies that carry out the process control (e.g., operators, panelists and supervisors) to identify the training needs and action plans. Experience indicates that the fundamental documents previously listed are often set aside, so they must be incorporated with the most up-to-date versions for new personnel training.

Analysis. This stage is based on the information obtained in the diagnostics stage. Several types of deviations can be found in this stage, which depends on the particularities of each case (process type, management style, organizational culture, etc.). However, at this stage, it is advisable to group the variances into the following aspects:

1. **Rationalization.** It is important to be clear that rationalization is not an alarm removal process but a process of managing alarms in the right place at the right time. Depending on the configuration of the control systems, there are processes that are controlled in a certain place and monitored in the main control room. For example, a truck loading station usually has a special control workstation—different from the main control room—that is only monitored. However, redundancy is usually incurred when setting alarms, causing them to appear on both stations. This condition can lead to a lack of operational discipline, since being at both stations, the operators can expect the other to attend to them and vice versa, or worse, the alarm is not attended after a long period of time. For this type of case, it is advisable to establish a level of criticality of alarms that should go in redundancy towards the main control room, given its level of impact on the process and its security or its interrelationship with the other processes of an installation (processing, storage, etc.).
   Other types of rationalization examples can be found in the alerts of the same system (warning of upcoming maintenance, capacity alerts, etc.), which are usually seen as alarms and distract the attention of operations staff. Usually, the architectures of the control systems have maintenance or support modules managed by the maintenance or instrumentation personnel. These types of alarms can be managed through these modules only, allowing them to clear the control screens of the process itself.
2. **Review of inconsistencies and failures.** It is important to identify the nature of the alarms that are presented on a recurring basis during normal operating conditions. The main causes to be analyzed include:
   - Changes in process capabilities (processing load increases, changes in operating conditions, different modes of operation, etc.)
   - Inadequate calibration of equipment or instruments
   - Uncontrolled changes in alarm settings in the control system
   - Errors in the process design.

   This review requires a detailed analysis in the engineering and design of the equipment, especially in the instruments and equipment associated with the recurrence of alarms. For example, it is common for an automatic cutting or emergency valve to set

an opening or closing time. In case this time is extended from a defined value, an alarm will be triggered indicating a problem during operation. However, since the valves complete their stroke, there is a phenomenon of normalization of this deviation since the operator trusts that the valve will open or close completely and the alarm will be recognized without further action or analysis. This can be risky in the case of a real occurrence. In this situation, it is advisable to check or calibrate the drive time of the valves and inspect for any internal damage to the valve or actuator to eliminate the recurrence of such alarms.

Another example is when uncontrolled changes are made to alarm values by operational personnel to use alarms as an alert mechanism when reaching a desired value, distorting the functionality of alarms and adopting them as a means of control. This constitutes a deviation from the operational discipline that must be promptly attenuated.

3. **Adequacy to the process.** Based on the information reviewed at the diagnostics stage, this aspect requires a detailed analysis of the process and the changes that have been made to it. For example, when plant capacity expansions are carried out, it leads to flow increases in certain process streams, implying that the configuration of the instruments must also be modified (rangeability), along with the new alarm values according to the new flows to be handled. Without these changes, recurring alarms are often presented and the phenomenon of normalization of deviation from operational personnel occurs.

After completing the analysis and identifying the causes of the recurrence of alarms, it is necessary to review the operating procedures that allow the proper management of the alarms, which establish the necessary permissions to make changes. In this regard, training opportunities for operational staff should be identified, as well.

4. **Implementation.** Since changes to the alarm system will be made in this stage and the proper management of change (MoC) must be applied, this stage should only begin after the organization has validated and approved the final reports of the previous stages.

Alarm management implementation should be aligned with the safety policies of the organization, especially with the elements of PSM, so that its implementation will be integral and effective to establish

TABLE 2. Relationship of alarm management and PSM

PSM elements		Diagnostic	Analysis	Implementation	Operation
Commit to process safety	Leadership	X	X	X	X
	Compliance with standards	X	X	X	X
	Process safety competency	X	X	X	X
	Workforce involvement	X	X	X	X
	Stakeholder outreach	X	X	X	X
Understand hazards and risks	Process knowledge management	X	X	X	X
	Hazard and risks analysis	X	X	X	X
Manage risks	Operating procedures		X	X	X
	Safe work practices			X	X
	Asset integrity and reliability	X	X	X	X
	Contractor management			X	X
	Training and performance assurance			X	X
	MoC	X	X	X	X
	Operational readiness			X	X
	Conduct of operations	X	X	X	X
	Emergency management	X	X	X	X
	Incident investigation	X	X	X	X
Learn from experience	Measurement and metrics			X	X
	Auditing				X
	Continuous improvement				X

TABLE 3. KPI proposal

KPI description	KPI	Goal	PSM elements linked
Level of acceptability	No. of alarms/5 min	< 1	All elements
Reliability of control system	No. of fails registered/5 min	< 1	1, 2, 6, 7, 10, 12, 15, 16, 18, 19, 20
Operational discipline	No. of bypasses or overriden alarms	0	1, 2, 3, 4, 8, 9, 10, 12, 13, 14, 15, 18, 19, 20
Readiness for emergency response	% of operative alarms or interlock devices during tests	100%	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 12, 14, 15, 16, 18, 19, 20
Standards compliance	% of alarms or interlock devices that comply with codes or standards	100%	1, 2, 4, 5, 6, 7, 10, 13, 18, 19, 20
MoC	% of process changes (alarms, signs, etc.) analyzed and registered	100%	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 13, 15, 16, 17, 18, 19, 20
Management of operating procedures	% of updated or reviewed procedures/yr	100%	1, 2, 3, 4, 6, 8, 12, 14, 15, 16, 18, 19, 20
Competencies certification	% of trained staff in process control	100%	1, 3, 4, 6, 12, 14, 15, 16, 18, 19, 20

an operational discipline in the staff and achieve a link to the operational philosophy with the safety culture of the organization. This is the critical moment that organizations face to succeed in this implementation.

Identifying the elements of PSM. According to the elements established for PSM[1], during alarm management implementation stages, specific elements are developed that facilitate the development of process management or complement the existing ones.

To identify and interrelate the stages of the development of alarm management with the main elements of PSM, **TABLE 2** proposes a conceptual guide scheme. The scheme in **TABLE 2** shows that the implementation of alarm management covers all elements of PSM, making it easier for the organization to implement it, upgrading the organization's operational and safety standards.

From diagnosis as a baseline and then analysis, implementation and sustainable operation, several elements develop during stages of implementation. Other elements are developed as their need is determined and incorporated or improved.

For example, the revision of the control philosophy during the diagnostics stage serves as the basis for the analysis of the process and validates the strategy or philosophy of alarms, as well as for the review and elaboration of better staff training plans and position profiles for the incorporation of new talents. Finally, this document must be updated each time a change is made, which must be properly managed and be part of the continuous improvement of the organization.

Another example is how the criteria for incident investigation are established or determined. This is one of the most important elements of PSM and where alarm management takes a very important role. Success of its management constitutes a source of predictive information to analyze deviations in operational discipline, equipment reliability and staff competence, among others. In addition, during the diagnostic and analysis stages, it can be determined whether it is necessary to implement a certain research methodology according to the new requirements of the process and policies of the organization.

Establishing management indicators. Two large groups of management indicators exist: lagging and leading. This analysis will focus on the latter since it is more aligned to the objective of PSM, which is to ensure the reliability of anticipating failures in processes based on the continuous analysis of deviations and on a solid management of information.

TABLE 3 details a list of indicators related to alarm management that can be incorporated into PSM dashboards in organizations that have implemented it. It is important to note that these indicators—all related to alarm management—are geared with the elements of PSM and could facilitate performance measurement and be integrated into the organization's PSM scheme.

General recommendations. The following are general recommendations to establishing alarm management:

- Consider the implementation of alarm management as a pillar for strengthening or consolidating PSM, involving the resources needed to achieve the desired results.
- The alarm management makes PSM assurance easier due to its aspects being linked to PSM elements.
- Consider a project approach to its implementation, especially for organizations that have a PMO and can establish management under project management guidelines. This action will speed up and facilitate its implementation.
- Put a lot of emphasis on validations or approvals during deployment. It is advisable to apply an appropriate transition plan to avoid uncoordinated actions during the implementation of a certain stage. HP

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Valve solutions for environmental wastewater

DeZURIK, a leading valve manufacturer in the industrial and municipal markets, offers a wide variety of valve solutions for environmental wastewater systems, including grey water intake, pump isolation, pump surge control and membrane bioreactor isolation.

The company's broad range of valves (FIG. 1) includes the DeZURIK, APCO, Hilton, Willamette and Red Valve brands. These brands, combined with in-depth expertise of its technical staff, position DeZURIK to analyze environmental wastewater systems and provide options for practical, cost-effective solutions for handling corrosive, erosive, abrasive and viscous media. The DeZURIK product line includes a wide variety of butterfly valves, eccentric plug valves, knife gate valves, check valves, pump control valves, surge relief valves, air release/air vacuum valves, and more.

DeZURIK is an industry leader with high-quality, AWWA C504 and C517 isolation and process flow control valves that are up to the unique challenges of industrial environmental wastewater. From traditional dissolved gas flotation (DGF) systems to more advanced membrane bioreactors, DeZURIK can custom match valves to the application's exact flow and water quality conditions and provide detailed flow and pump efficiency analysis.

Safely measure low-differential pressure of corrosives

The heavy-duty Ashcroft® 5503 low-differential pressure gauge (FIG. 2) now offers extra protection against a wide variety of corrosive liquids and gases. The new "LH" option adds Ashcroft 700 series diaphragm seals with flexible capillaries to any 5503 gauge ranged from 60 in. H_2O (3 psi)–160 in. H_2O (6 psi). Choices of wetted materials include 316 SS, tantalum, titanium, Hastelloy® B, Hastelloy® C 276, K-Monel® and Carpenter® 20. Dial sizes of 4 in. (100 mm) and 6 in. (160 mm) are available along with optional features including liquid fill, electrical contacts and a choice of mounting hardware.

Variable area flowmeters for process industries

Brooks Instrument, a world leader in advanced flow, pressure and vapor delivery solutions, has added the GT1600 Series of glass tube variable area flowmeters (FIG. 3) to its family of variable area flowmeter products.

Suitable for a wide variety of industries—from chemical manufacturing to pharmaceutical production to water treatment and distribution—the GT1600 is ideal for low- and high-flow gas and liquid applications where viewing the process is important.

The rugged flowmeter features high-quality design and materials, such as 316 stainless-steel construction and a polycarbonate shield, to ensure safety and longevity for both indoor and outdoor use.

For ease of use, the adjustable, transparent scale improves readability and allows for offset correction to compensate for process variation. In addition, the process connection can be rotated 360°

FIG. 2. The heavy-duty Ashcroft® 5503 low-differential pressure gauge.

FIG. 1. The DeZURIK range of valves includes the DeZURIK, APCO, Hilton, Willamette and Red Valve brands.

FIG. 3. The Brooks Instrument GT1600 Series of glass tube variable area flowmeters.

so users can view from all directions. An alarm option is also available for automatic monitoring of critical flow conditions.

Configured for simple installation, the GT1600 is available with a variety of connections to fit existing piping arrangements or mount to a panel or wall. It can also work as a drop-in retrofit for the Brooks Instrument GT1000, GT1300 and Full-View® 1100 Series of flowmeters, which have been widely used for decades.

The GT1600 is fashioned for easy maintenance. For in-situ cleaning, the glass tube and float can be replaced without removing the flowmeter from the piping, saving time and cost.

Enhanced thermal imaging flare stack solution

AMETEK Land, a leader in non-contact temperature measurement and combustion emissions monitoring for industrial applications, has enhanced its flare stack monitoring thermal imaging solution with the inclusion of its advanced image processing IMAGEPro software to deliver accurate and reliable monitoring of the flame and the pilot light at the flare stack.

AMETEK Land's flare stack monitoring solution (FIG. 4) includes an infrared imager that produces high-resolution thermal images of the target, from any distance. This allows the camera to be positioned at a safe distance from the flame and makes it easily accessible for installation and maintenance.

The solution's IMAGEPro software monitors, captures and displays data from multiple thermal imaging cameras simultaneously to provide real-time analysis and exceptional functionality, delivering protection against unwanted emissions. Detailed visualization of the thermal data and the ability to set alarms enable the system to warn if action is required.

In addition to producing a visual image, AMETEK Land's imager also detects the infrared radiation emitted from the flame. This means the camera sees the flame, whether it is colored or clear, no matter the weather.

With a wide detection range from 100°C–1,000°C (212°F–1,832°F), even if the gas composition changes and affects the temperature of the flame, the imager continues to supply an accurate measurement. The range is also high enough to ensure that background heat is ignored, and it operates in ambient temperatures from –20°C–60°C (–4°F–140°F), making it suitable for installation in almost any location.

The ability to select multiple regions of interest ensures that measurements continue to be made even when the flame is moved by wind conditions. By delivering accurate and reliable monitoring, the solution helps ensure that plants can meet flare stack emissions requirements in a safe and efficient operation.

Software to schedule, plan and track quality assurance (QA) test activities

ESC Spectrum has released QAInsight, a subscription-based software that helps utilities and other industrial companies solve the challenges of scheduling, planning and tracking a myriad of activities related to performing QA tests required by state and federal agencies.

QAInsight serves as a company's single source for QA test data, ensuring access to information across different facilities and departments, as well as eliminating mistakes or incorrect data resulting from spreadsheets or other error-prone collection and storage methods.

QAInsight users can see an overview of their QA activities (including QA test completion dates, operating data and recertification event deadlines), color-coded to help them quickly set priorities.

While QAInsight can be configured to work with any data acquisition system (DAS), it automatically imports critical information from ESC Spectrum's StackVision™ DAS.

Advanced redundant control system for emergency shutdown situations

Emerson has released its ASCO™ 141 Series advanced redundant control system (ARCS) to provide a redundant solution for a variety of emergency shutdown valve applications. It includes various redundant solenoid configurations to enhance the reliability of the process and meet specific safety or reliability requirements in automation processes. The single inlet/single outlet design provides a streamlined installation process, while almost eliminating potential failure points.

The ASCO 141 Series ARCS is designed for use as a component in safety instrumented systems. Utilizing 1oo2, 2oo2 or 2oo3 voting solenoids to enhance the reliability of the circuit, it functions as a redundant pneumatics tripping device to control the pilot air signal to a process valve actuator. The ARCS features either two or four electrically actuated solenoid valves, visual indicators and a manually controlled bypass or isolation valve. The unique control functionality allows for maintenance of the solenoid valves without having to shut down the process valve. In fact, the use of the maintenance bypass or isolation valve is not required for functional testing of the ARCS unit—a downtime-

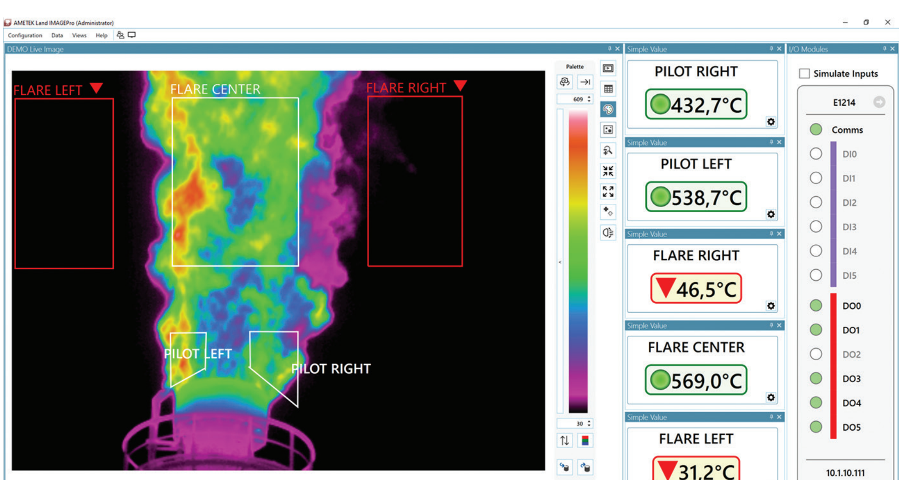

FIG. 4. AMETEK Land's enhanced flare stack monitoring thermal imaging solution.

reducing feature not possible with common bypass functions.

With just a single part number, the ASCO 141 series ARCS features several advances that simplify specification, installation and operation. Supplied as a fully integrated, comprehensive solution using a manifold instead of individual valves, ARCS comes pre-tested from the factory and ready to install.

The direct valve-to-valve design eliminates pipework and fittings between the solenoid valves and minimizes leak points for increased reliability and a lower total cost of ownership. A status indicator with feedback helps facilitate preventive maintenance while providing online fault detection and digital input feedback (via pressure switches or Emerson-exclusive GO Switch options) to the control room. For additional peace of mind, the ASCO 327 series 3/2-way direct acting solenoid valves included on the ARCS manifold are certified to SIL 3 capable (exida) standards.

A direct-acting platform with advanced diagnostic capability and online maintenance features, ARCS is suitable for a wide variety of valve piloting applications to meet both safety and operational availability requirements.

MSS publishes revised standard for diaphragm valves

The Manufacturers Standardization Society (MSS) of the Valve and Fittings Industry has announced that SP-88-2021, Diaphragm Valves, has been revised and published by the MSS.

Standard Practice (SP)-88 has served as an industry norm for more than 43 yr, providing a framework for the limitations and requirements of valves in which a nonmetallic, resilient diaphragm is used to separate the working parts of the valve from the line fluid and also functions in conjunction with other parts as a valve closure member.

This Standard Practice applies to valves for general liquid and gas service that effect valve closure by means of a resilient diaphragm sealing against a weir or a diaphragm acting in conjunction with a separate or integral disk-member sealing against a seat, having equal sealing capability in either flow direction, and having diaphragms being essentially made of elastomeric or plastic material or combinations thereof.

SP-88 continues to be maintained under the consensus of MSS Technical Committee 406, Diaphragm Valves. The revised Standard Practice, MSS SP-88-2021, is now available from authorized U.S. and global distributors. It has been published in an electronic version (PDF) and in book format.

3-in-1 industrial sensor with vibration, temperature and speed

Petasense, a leader in Industrial Internet of Things (IIoT) sensors and asset reliability and optimization, launched the first industrial wired sensor that combines vibration, temperature and speed detection into a single sensor. The Vibration Sensor (VSx), shown in

FIG. 5, plugs into the Petasense Transmitter (Tx) to detect common failures in variable speed, batch or spared assets.

Until now, these assets have been challenging to monitor because readings are often taken under different operating conditions, resulting in missed readings or data points that are not comparable across time.

Integrated-speed detection within the VSx allows users to take measurements only during the specified speed ranges or when the asset is operating. Embedded smart sensing allows the sensors to communicate with each other, providing synchronized readings across multiple sensors on the asset train. By taking simultaneous measurements, users are able to better diagnose developing problems.

The VSx follows the recent launch of Petasense's wireless Vibration Mote (VM3) and provides an option for applications or customers that want a wired sensor. By wiring the VSx into the Petasense Transmitter, users can take advantage of affordable battery-less wireless monitoring. Eliminating battery change-outs will help to accelerate IIoT deployments, which has been a common challenge for large-scale projects.

Data from the VSx is sent from the Transmitter securely over standard WiFi to the Petasense Asset Reliability and Optimization (ARO) Cloud. ARO uses machine-learning algorithms, coupled with a comprehensive library of assets and failure modes, to continuously assess asset health. Web and mobile apps allow users to monitor assets remotely and receive actionable insights through real-time notifications.

FIG. 5. Petasense has released its Vibration Sensor (VSx).

FIG. 6. Brüel & Kjær Vibro has launched VIBROSTORE 100, providing vibration level and bearing wear monitoring for balance-of-plant machines.

Quick and easy machine health monitoring

Brüel & Kjær Vibro (B&K Vibro), one of the leading worldwide independent suppliers of condition monitoring solutions for rotating machinery, has launched VIBROSTORE 100 (FIG. 6), a palm-sized device that provides vibration level and bearing wear monitoring for balance-of-plant machines at the push of a button.

The lightweight device can be used single-handedly and enables even untrained personnel to take vibration measurements and assess a semi-critical machine's overall vibration condition. The instrument is equipped with a preset, cable-connected, high-quality B&K Vibro acceleration sensor. Once the type and size of the machine based on ISO 10816 and its running speed are entered, a one-button push can perform the measurement. A traffic-light display immediately indicates the severity of the vibration based on the built-in ISO 10816 alarm limits (velocity in mm/sec or in./sec). The main screen also shows the rolling-element bearing condition in bearing damage units measurement (BDU) and total g (RMS acceleration). The display of the vibration level in frequency ranges indicates the most common machine faults, such as imbalance, misalignment or looseness.

VIBROSTORE 100 is available either as standalone or packaged with the B&K Vibro Report & Route Manager software, a powerful and highly functional route editor and analysis software.

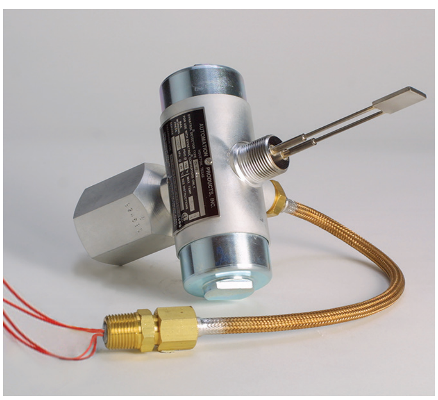

FIG. 7. The Dynatrol® CL-10GPT proportional level detector.

Small vessel proportional level detector for high-temperature processes

The Dynatrol® CL-10GPT proportional level detector (FIG. 7) is designed specifically to control liquid levels in pilot plants, processing, small vessels or anywhere it is necessary to obtain proportional level control over a precise range. Applications may include hydrocarbons, petrochemicals, pulping chemicals, slurries, etc. The EC-103C(G) Control Unit is paired with the Detector and can activate electro-pneumatic transducers, valve positioners, indicators, controllers or other DC current devices.

The Dynatrol CL-10GPT and EC-103C(G) accurately monitor and control an extremely precise liquid level range due to a unique high-resolution, proportional output signal. This unique control operates reliably under varying frequency power supplies or harsh process conditions, such as high pressures and high temperatures.

Installation is simple, and the separate control unit permits installation at any convenient location. The detector is mounted through a ¾-in. half-coupling at the point of desired level detection, eliminating costly flanges, float chamber or fittings. The Dynatrol CL-10GPT and EC-103C(G) operate on either a 50Hz or 60HZ power supply.

Dynatrol detectors are constructed for a long operating life and provide years of dependable service in industrial environments. All units are built in accordance with Class I, Group D; Class II, Groups E, F & G; and Class III services. HP

Technology and Business Information for the Global Gas Processing Industry

GAS PROCESSING & LNG

GasProcessingNews.com | MARCH/APRIL 2021

GREEN TECHNOLOGIES

Reduce emissions and save energy with an unconventional FGRS

Obtain accurate NO_x values to reduce emissions from combustion

GTI makes big strides in hydrogen projects, advocacy

DIGITALIZATION

An integrated, intelligent gathering and processing super system

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Evolution and innovation for an increasingly dispersed LNG market

Gulf Energy

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Pipeline & Gas Journal

EDITORIAL COMMENT

A. BLUME,
Editor-in-Chief

What are "green technologies," and why do we need them in gas processing and LNG? The answer is as obvious to many engineers in the energy space as it is to environmental scientists: cleaner fuels result in a cleaner and more sustainable environment. Less emissions and fewer pollutants are needed in the production, transport, distribution and usage of fossil energy, including natural gas, to sustain human and environmental health and to diversify global and regional energy sources.

A number of initiatives are underway to support these efforts across the midstream, downstream and renewable energy sectors, including the capture and storage of more CO_2 emissions; a greater focus on lifecycle emissions, particularly in LNG; increased recycling of plastics and wastes; and the expansion of renewable energy infrastructure and H_2 production. **Note:** For more insight into technical applications and trends in the H_2 sector, please consult our new technical journal, *H2Tech* (www.H2-Tech.com).

To support the industry's efforts to decarbonize and transition to cleaner sources of energy, the U.S. Department of Energy's three applied energy laboratories are studying the integration of hybrid energy systems. The joint effort outlines novel concepts to simultaneously leverage diverse energy generators—including renewable, nuclear and fossil fuels with carbon capture—to provide power, heat, clean water, fuels and chemicals.

One application example is a hypothetical, tightly coupled industrial energy park that uses heat and electricity from flexible, advanced nuclear reactors, small-scale fossil fuel generators, and renewable energy to produce electricity and H_2 from electrolysis. Such flexibility could provide an abundant supply of clean energy for larger, net-zero-emissions energy systems to power a cleaner future for society. **GP**

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Cover Image: At the Port of Rotterdam, Shell plans to build a 200-MW electrolyzer that is intended to start operations by 2023 to produce approximately 50,000 kg/d–60,000 kg/d of hydrogen. The green hydrogen initially will be used at the Shell refinery in Pernis (pictured) to partially decarbonize the production of fossil fuels. Photo courtesy of Photographic Services, Shell International Ltd.

BCCK signs deal for landfill gas-to-energy plant

BCCK Holding Co. (BCCK) signed an agreement with Archaea Energy to provide a 13,700-sft^3/min Style IV NiTech nitrogen rejection unit (NRU) to the world's largest high-BTU landfill gas-to-energy plant in Pennsylvania, U.S.

The Style IV NiTech process design features a new, modular-skidded design that allows greater flexibility with respect to compositional changes or flow capacity changes. BCCK's NiTech technology performs a key role in transforming landfill gas into nearly 100% pure renewable natural gas.

The NRUs, which are engineered in-house and fabricated at BCCK's fabrication facility, deliver smaller footprint, less compression requirements in terms of horsepower and higher recovery, all at reduced CAPEX.

Australia marks LNG export record in 2020

Australia exported a record 78 MMt of LNG in 2020, up from 77.5 MMt in 2019, according to estimates by EnergyQuest. The record-high levels were reported despite the disruptions to Gorgon output, Prelude not producing LNG since early February 2020, production issues at Wheatstone and COVID-19 demand destruction for LNG, especially early in the year.

Australian production was above Qatar's estimated nameplate capacity of 77 MMtpy. The Australian projects operated at 89% of total nameplate capacity of 87.8 MMtpy. Australia's 2020 total LNG export revenue was estimated at A$36.1 B, a decrease from A$48.7 B in 2019. LNG export revenue was impacted by lower oil prices seen through much of the year since April, coupled with low spot prices for LNG.

Meanwhile, Woodside is looking to sell a 50% stake in the new production train at its Pluto LNG plant in Western Australia, as a precondition for a planned, $11-B expansion at its Scarborough gas development. The renewed push by Australia's largest independent gas producer on the 8-metric-MMtpy expansion project comes after last year's COVID-19-induced collapse in oil and gas prices drove Woodside's underlying annual profit down 58% to $447 MM.

Energy Transfer to buy Enable Midstream for $2.6 B

Energy Transfer LP plans to buy Enable Midstream Partners to strengthen its natural gas transportation business as it faces a legal battle that could shut its Dakota Access crude pipeline. The $2.6-B deal, announced in mid-February, came just weeks after a U.S. appeals court dealt a blow to the 557,000-bpd Dakota pipeline, raising the chances that it will be shut pending an environmental review.

Regulators have also denied permits to notable natural gas pipelines, while the new Biden administration has effectively canceled the Keystone XL pipeline project and has indicated its intention to limit oil and gas drilling on federal lands.

The acquisition was valued at about $7.2 B, including debt. The deal will provide gas gathering and processing assets in the Arkoma basin across Oklahoma and Arkansas, as well as the Haynesville Shale in East Texas and North Louisiana. Energy Transfer expects the combined company to generate more than $100 MM of annual run-rate cost and efficiency savings.

Tema LNG regas facility begins deliveries

Tema LNG's FRU arrived in Ghana in early January, allowing Tema LNG Terminal Co. to start delivering LNG to customers in Q1 2021. The LNG is supplied under a long-term contract with Shell.

Tema LNG, backed by Helios Investment Partners and Africa Infrastructure Investment Managers, is the first offshore LNG receiving terminal in sub-Saharan Africa. The terminal employs the innovative combination of the FRU twinned with an existing LNG carrier to receive, store and regasify 1.7 MMtpy of LNG.

This system provides Ghana with all the functionality of a large scale FRU terminal, but with added flexibility. This enables Ghana National Petroleum Corp. to supply reliable and cost-effective gas into the Tema power and industrial enclave while strengthening West Africa's energy security.

Israel to link Leviathan gas field to Egypt LNG plants

Israel and Egypt have agreed to build a pipeline to connect Israel's offshore Leviathan natural gas field to LNG terminals in northern Egypt. Palestine has also signed an agreement with Egypt's energy minister, who visited Israel and the occupied West Bank, to develop a gas field off the coast of Gaza. Israel and Egypt are both looking for new ways to expand the development of East Mediterranean natural gas.

Israel's Leviathan field, located 130 km (80 mi) off Israel's coast, already supplies the Israeli domestic market and exports gas to Jordan and Egypt. Its shareholders include Chevron and Delek Drilling. Leviathan's partners have been exploring options to expand the project, including a floating LNG facility or a subsea pipeline to link up with LNG terminals in Egypt that have been idled or run at less than their nameplate capacity.

Meanwhile, Palestine has asked Egypt for help in developing the Gaza Marine field with the project's partners, the Palestine Investment Fund, the sovereign fund of the Palestinian Authority and Consolidated Contractors Co. Gaza Marine sits approximately 30 km (19 mi) off the Palestinian enclave's coast and is estimated to hold more than 1 Tft^3 of natural gas.

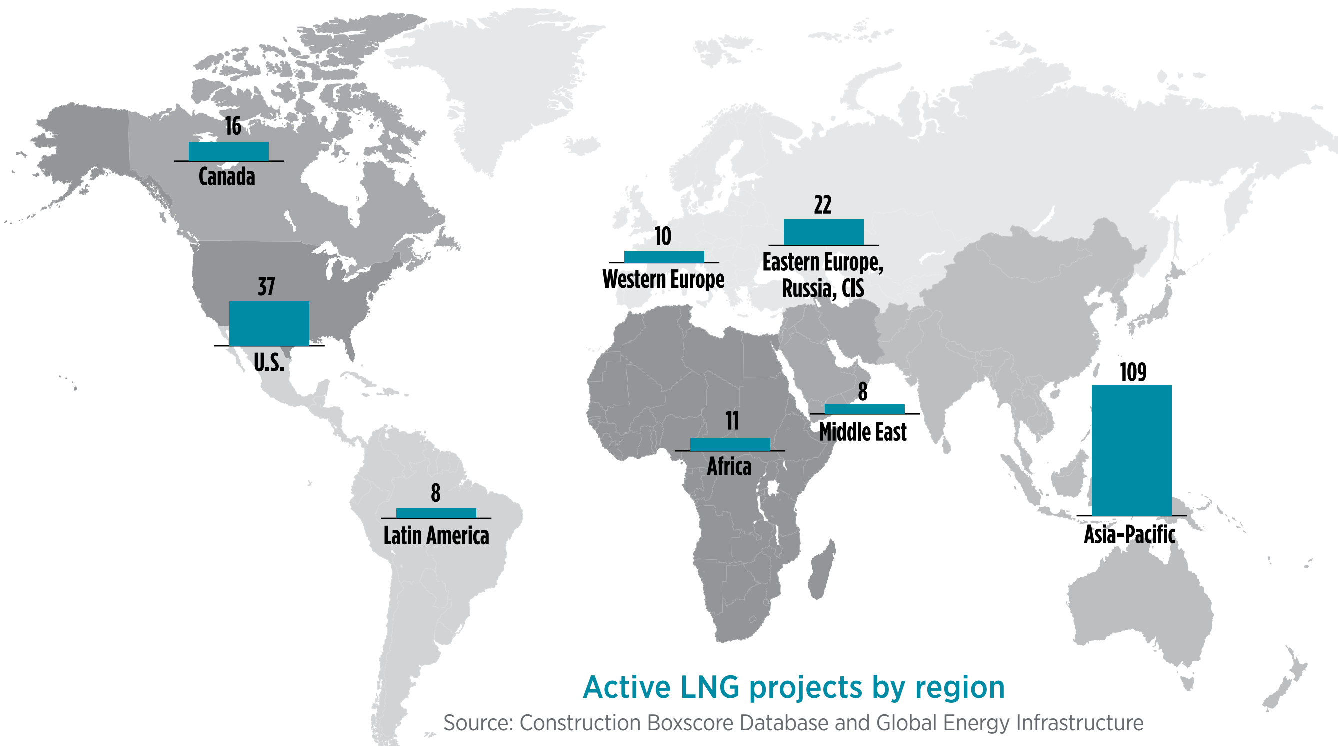
Technip, Chiyoda awarded LNG contracts for Qatar LNG

TechnipFMC announced that CTJV, a joint venture between Chiyoda Corp. and Technip Energies, has been awarded a major EPCC contract by Qatar Petroleum for the onshore facilities of the North Field East project.

The award will cover the delivery of four mega-trains, each with a capacity of 8 MMtpy of LNG and associated utility facilities. It will include a large CO_2 capture and sequestration facility, leading to more than 25% reduction of greenhouse gas emissions when compared to similar LNG facilities.

The new facilities will receive approximately 6 Bsft^{3}d of feed gas from the eastern sector of Qatar's North Field, which is the largest nonassociated gas field in the world. The expansion project will produce approximately 33 MMtpy of additional LNG, increasing Qatar's total production from 77 MMtpy to 110 MMtpy.

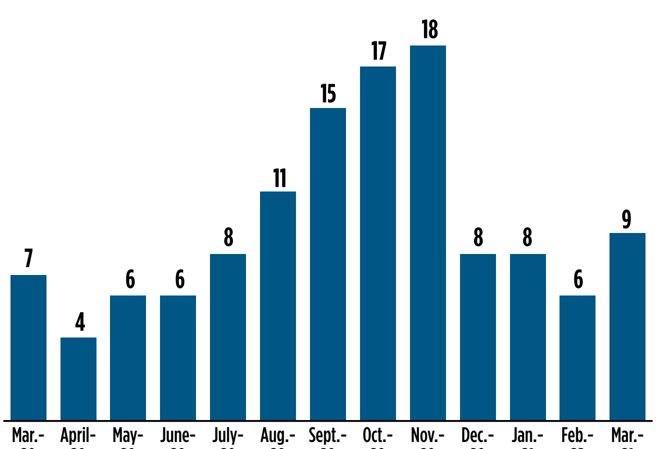
According to Shell, global LNG demand is forecast to nearly double to 700 MMtpy by 2040. The Asia-Pacific region will be the leader in LNG demand growth throughout the forecast period. Gulf Energy Information's Construction Boxscore and Global Energy Infrastructure (GEI) databases show that the Asia-Pacific region accounts for nearly half of active capital projects in the global LNG industry. Most of these investments are for new LNG import infrastructure in China and India. Both nations are investing heavily to increase natural gas usage in their total energy mix. Globally, nearly 80% of active LNG projects are in preconstruction phases. **GP**



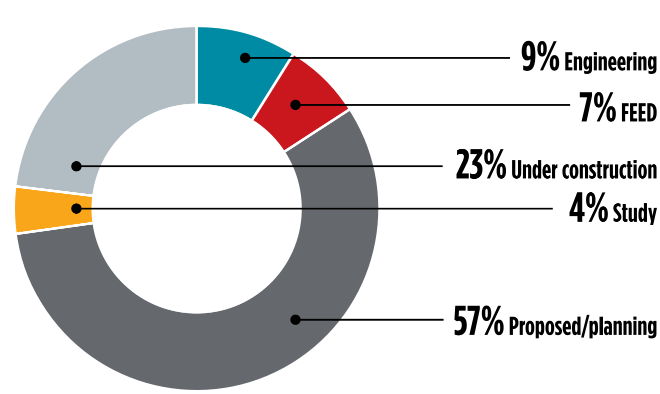
Active LNG projects by region

Source: Construction Boxscore Database and Global Energy Infrastructure

New gas processing/LNG project announcements, March 2020–March 2021

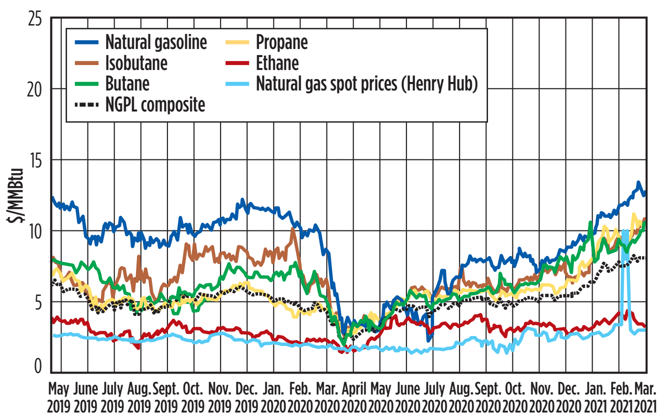


Active LNG project market share by activity level

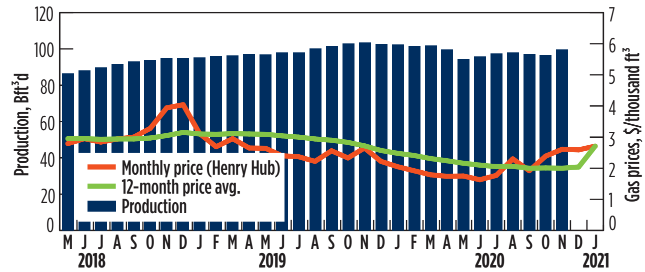


Full-year 2020 data for LNG exports from the U.S., released by the EIA in March, show that U.S. LNG exports averaged 6.6 Bft^3d on a yearly basis and increased 1.6 Bft^3d (32%) year-on-year. Export levels were high from January–May and began to increase again in October–December after a record-low summer slump. The late-year increase was largely due to extremely cold weather and unplanned outages at LNG export facilities in several countries, which caused Asian LNG spot prices to climb. LNG exports also increased due to the addition of export capacity at U.S. terminals including Freeport, Cameron, Corpus Christi and Elba Island. **GP**

U.S. natural gas spot prices at Henry Hub and NGL spot prices at Mont Belvieu, $/MMBtu

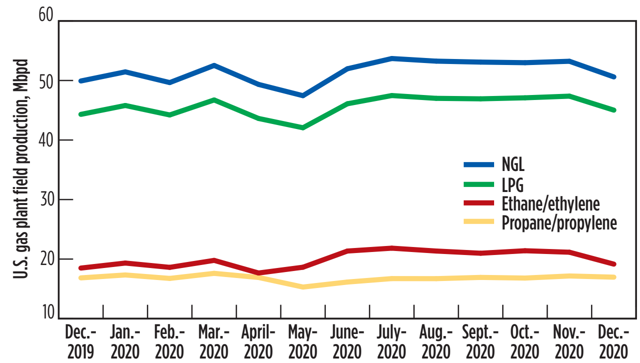


U.S. gas production (Bft³d) and prices ($/Mcf)



Production equals U.S. marketed production, wet gas. Source: EIA.

U.S. natural gas plant field production of NGL, LPG, ethane and propane, Mbpd



Source: U.S. EIA

India leaps forward on natural gas infrastructure

G. FELLER, Contributing Writer

The operator of Europe's largest natural gas transmission network is working to invest in the Indian gas pipeline business. Executives at Italy's Snam are working with India's Ministry of Petroleum and Natural Gas, as well as other Indian government officials, regulators and industrial executives to explore the full scope of investment opportunities. Negotiations include several categories: hydrogen (H_2) fuel, gas storage and small-scale liquefaction technologies.

Influx of interest. In late 2020, Snam set up a partnership with Indian infrastructure and energy group Adani to develop an H_2 business in India and abroad, and to use biogas for low-carbon transport projects. Snam has also signed an agreement with state-owned energy giant Indian Oil Corp. Ltd. (IOCL) for collaboration on energy transition projects, including gas storage and regasification.

Furthermore, Snam has struck a deal with Indian renewable energy company Greenko to research the production of electrolyzer-produced H_2. Under the agreement, the two companies will collaborate on the study of H_2 production using renewable power, on the design of H_2-ready infrastructure and on applications for both industry and transport, including fuel cell mobility.

Snam CEO, Marco Alverà, commented on the deals, "We have the opportunity to bring a valuable contribution to a country that is strongly committed to the energy transition and which presents many opportunities. These agreements aim at promoting the growth of green hydrogen in India and other countries to help decarbonize industry and transport and at further developing natural gas and hydrogen mobility in a huge market."

At present, Snam operates businesses in Italy, the UK, France, Austria, Greece and China. The company plans to use its deep gas sector knowledge to propel itself into the Indian marketplace. "The significant push toward cleaner energy shift and toward gas is what makes the country interesting for Snam. This will require infrastructures and an integrated management of those infrastructures," Alverà said.

"Snam is also working on an innovative modular approach to liquefaction that would enable liquefaction of gas at very competitive costs to foster city gas distribution and to monetize local stranded gas reserves," Alverà said. Many of India's small gas fields are not yet connected by pipeline, but inexpensive liquefaction facilities could help monetize this gas for transport and other uses.

Indian government pushes for gas expansion. State-owned IOCL operates a 13,391-km network of crude oil, natural gas and product pipelines, with a capacity of 1.896 MMbpd of oil and 9.5 MMsm^{3}d of natural gas. This capacity accounts for approximately 30% of the nation's total pipeline network. The nation's top three companies—IOCL, Hindustan Petroleum Corp. Ltd. (HPCL) and Bharat Petroleum Corp. Ltd. (BPCL)—contribute more than 80% of the total length of the gas pipeline network in the country.

Last year, India's central government announced a plan to invest $9.97 B to expand the gas pipeline network across the country. Even with the COVID-19 pandemic's dampening effect on the national economy, experts inside the government and the private sector believe that India's consumption of natural gas will increase more than three-fold over the next 10 yr, making the investments essential.

LNG regasification has become another national priority. H-Energy is a Mumbai-based, private firm that plans to invest $540.6 MM to build LNG terminals and lay down a 60-km pipeline. In 2018, H-Energy inaugurated India's first FSRU-based LNG regasification terminal at Jaigarh Port in Maharashtra.

Overall, India's Ministry of Petroleum and Natural Gas is targeting $100 B of investment in gas infrastructure by 2022.

Investment to support growing demand. India's energy demand is expected to double to 1,516 MM tons of oil equivalent (MMtoe) by 2035, from a total of 753.7 MMtoe in 2017. Furthermore, India's share in global primary energy consumption is projected to increase two-fold by 2035. LNG imports account for approximately 25% of the country's total natural gas demand, which is expected to double over the next 5 yr. To meet this rising demand for gas, the government wants to increase its LNG import capacity to 50 MMt.

To encourage greater capital flows into natural gas and oil, India's government allows 100% foreign direct investment (FDI) in upstream and private-sector refining projects. The FDI limit for public-sector refining projects was raised to 49% without any disinvestment or dilution of domestic equity in existing state-owned entities. The government previously approved fiscal incentives in 2018 to attract investments and technologies to improve the productivity of the country's oil and gas fields. When it enacted these measures, the Ministry of Petroleum and Natural Gas forecast hydrocarbon production worth $745.8 B over the next 20 yr. **GP**

GORDON FELLER has been writing about energy, particularly oil and gas, since his first magazine article was published in 1978, and he has been published in more than 50 industry magazines. He has undertaken numerous research and writing projects for large institutions, including the World Economic Forum, the World Bank, and the governments of Germany, the UAE (Abu Dhabi), Japan and Canada. He has also won more than two dozen competitive fellowships. Mr. Feller graduated with a master's degree from Columbia University in New York City, New York.

GTI's Hydrogen Technology Center makes big strides in H_2 projects, advocacy

K. WILEY, Executive Director, Hydrogen Technology Center, GTI

As the Executive Director of GTI's Hydrogen Technology Center, KRISTINE WILEY works across the organization to synchronize deep industry knowledge and technical expertise, as well as large-scale labs and test facilities to integrate the use of H_2 into the energy system. Addressing economy-wide decarbonization, the Hydrogen Technology Center brings together public-private partnerships to facilitate R&D to enable clean H_2 generation, transport, storage and utilization at scale while leveraging the existing robust energy infrastructure to facilitate the transition to a low-carbon future.

Ms. Wiley's career spans nearly two decades at GTI. Prior to her current role, she served as an R&D Director responsible for GTI's Environmental, Risk and Integrity Management programs. With a focus on reducing environmental impacts, she led collaborative research directly working with industry to develop solutions for the detection and mitigation of methane emissions from natural gas operations. At GTI, she has held positions of increasing responsibility in managing research addressing utility operations and environmental compliance to advance the use of low-carbon fuels, such as renewable natural gas.

Ms. Wiley holds a BA degree in biological sciences from the University of Chicago, as well as an MBA degree from the University of Chicago Booth School of Business.

To address the many challenges and opportunities in the world's energy future, the U.S.-headquartered, global-focused GTI recently launched a Hydrogen Technology Center with world-class research and development capabilities. *Gas Processing & LNG* spoke with Kristine Wiley, Executive Director, about the Center's ongoing and upcoming initiatives and projects, as well as projected technology adoption and use amid the worldwide expansion of H_2 infrastructure.

For extensive coverage of advances in H_2 technology, applications and trends, please consult Gulf Energy Information's new publication, *H_2Tech*. Visit www.H2-Tech.com for more information.

GP&LNG: Last year, GTI and the Electric Power Research Institute (EPRI) announced the formation of the $100-MM Low-Carbon Resources Initiative (LCRI), which aims to bring low-carbon power generation technologies to commercial scale by 2030. Can you share an update on the Initiative and the projects and strategies coming out of it?

KW: The LCRI is bringing together industry stakeholders to accelerate development and demonstration of low-carbon energy technologies through transformative, clean energy research and development. We launched LCRI in the autumn of 2020 with 18 anchor sponsors, and as of February 2021 have grown the membership to 35 sponsors and exceeded our goal of $100 MM in funding. It is a true demonstration of the energy industry's commitment to striving toward deep decarbonization across all sectors of the economy.

The LCRI intends to launch a set of initial projects that demonstrate key decarbonization pathways, providing resiliency, reliability and affordability while also reducing emissions. It is very important that we begin putting real technologies into operation as soon as possible.

Another key focus is our integrated energy systems analysis, which will help us evaluate scenarios for emissions reductions, identify low-cost technology pathways and quantify the impact of economy-wide decarbonization policies. This will be a key input to the LCRI roadmap, which will identify research and development (R&D) gaps, technology commercialization opportunities and investment needs, all of which will guide long-term R&D activities. The roadmap is expected to be released in Q2 2021.

GP&LNG: From your background in the midstream sector, can you talk a bit about the different ways that H_2 and renewable natural gas (RNG) can be blended or utilized in existing midstream operations, and how that will help reduce carbon footprint for midstream and LNG operators?

KW: Renewable natural gas and H_2 will both play important roles in transitioning to a low-carbon energy system. RNG is already being introduced into the existing natural gas system and is a key component to decarbonization strategies for gas companies. RNG facilities are taking waste from landfills or dairy farms, for example, and converting it into pipeline-quality gas for injection into the natural gas grid. In some cases, the RNG can be a carbon-negative fuel, depending on the initial feedstock used.

There are more than 100 operational RNG production facilities in the U.S., and that number is expected to grow as decarbonization commitments increase at the state, regional and even corporate levels. The benefit of RNG—assuming it has been processed to meet gas quality specifications—is that it is quite similar to the composition of natural gas, so the same

infrastructure can be used to transport and deliver it, and it can then be used in the same end-use applications.

H_2 is carbon-free and can be produced with low to zero emissions, offering a clean energy source. Similar to RNG, we expect H_2 to contribute to our low-carbon energy future and emerge as a significant energy carrier by 2040 across a variety of sectors and end-use applications, including industrial processes, transportation, buildings and power generation. The versatility of H_2, from ways to produce and use it across the full energy value chain, creates unprecedented opportunity for H_2 to become a greater part of our global energy system.

GP&LNG: In what regions or scenarios do you see the opportunity for repurposing existing natural gas storage and infrastructure to deliver H_2?

KW: One of the key drivers that has created an interest in H_2 is its potential role in large-scale energy storage. Renewable energy from wind and solar is not always available at the same time as peak demand for electricity. This has created a need for large-scale and seasonal energy storage that cannot be completely met by batteries or conventional methods like pumped hydropower. H_2 is the leading candidate to provide the storage that is needed to ensure continued growth of renewable power generation. Put simply, off-peak renewable power can be converted to H_2 via electrolysis and then injected into pipeline networks or underground storage for later use.

Blending H_2 into the natural gas system also offers a path toward decarbonization and reduction in emissions. Using a 20% blend of zero-carbon H_2 could reduce CO_2 emissions by approximately 7%. Several gas utilities, such as Dominion Energy, SoCal Gas and CenterPoint, have recently announced H_2 projects, many of which focus on H_2 blending into natural gas pipelines.

Creating H_2 hubs or networks where there is an aggregation of H_2-capable infrastructure and end users is another model being explored in the U.S. We are excited to be part of what will be the first large-scale demonstration of an H_2 network in our nation. With funding from the U.S. Department of Energy and an impressive list of industry partners, GTI, Frontier Energy and the University of Texas–Austin will be demonstrating an H_2 network at the university. Renewable H_2 will be produced and stored for use in an onsite H_2 fueling station and in a fuel cell to power a data center on the campus (**FIG. 1**).

This demonstration provides a stepping stone for building H_2 networks in other parts of the country, and hopefully for creating cities and communities fueled by H_2. The existing natural gas infrastructure will play an important role in making this happen.

At GTI, we think that H_2 will continue to be produced primarily from natural gas for quite some time—combined with carbon capture and storage to minimize its environmental footprint—while H_2 production from renewable sources will continue to grow. The natural gas infrastructure should have a continuing role for both near-term opportunities for H_2 and for the longer-term "green" H_2 economy. However, our pipeline infrastructure was built to transport natural gas, and as we explore injecting H_2 into that infrastructure, we must understand the impacts to the safety, reliability and integrity to the system. We are actively conducting collaborative research with industry, government agencies and academia to address this.

GP&LNG: In which sectors do you see H_2 taking off most quickly? Conversely, what obstacles must H_2 overcome to become a significant contributor to the world's energy supply?

KW: What we are seeing across the world is the acknowledgement that we need multiple solutions to achieve net-zero emissions. Significant progress is being made with renewables, energy efficiency, and electrification, but the only way to get there for certain sectors requiring high heat or energy density is with an energy-dense carrier, such as H_2. Long-haul heavy transportation, such as heavy-duty trucks, shipping, aviation and locomotives; industrial production, such as cement and steelmaking; or buildings in northern climates—all of these applications are well suited for H_2.

The transportation and delivery of H_2 is the highest-cost "link" in the H_2 value chain. Building new infrastructure is expensive, so using our existing gas infrastructure to store and deliver H_2 to where we need it, when we need it, is a great opportunity to help reduce those costs and provide continued reliability of energy supply to end users.

As we move down the value chain and evaluate the potential of using H_2 in various sectors of our economy, technical challenges must be addressed depending on the end-use application. For example, with residential applications, GTI and others are conducting research to understand the impact of H_2 on existing appliances to ensure that they operate properly and safely when a new source of fuel is being used. Similar research is occurring for the commercial, industrial and power generation sectors.

GP&LNG: What do you see as the most promising areas for the utilization of RNG as a fuel/feedstock?

KW: One of the most attractive features of RNG is the ability to use it in nearly any application or sector that uses

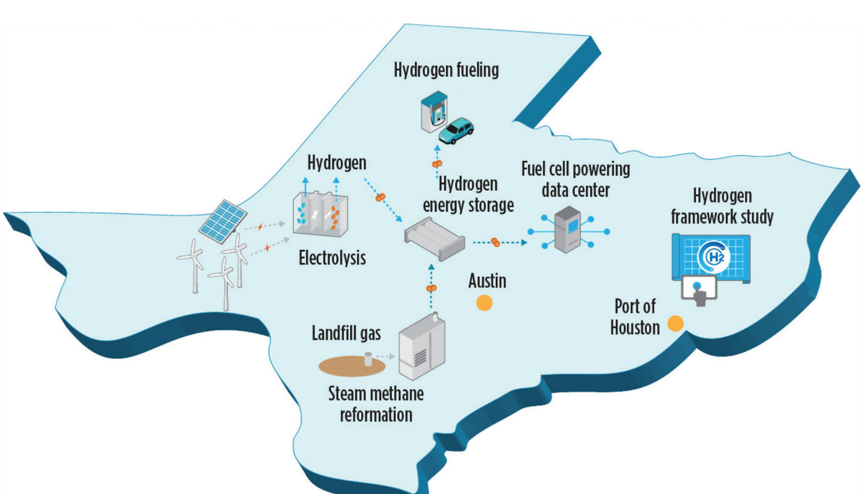


FIG. 1. GTI's Hydrogen Network Demonstration projects in Texas. Figure: Frontier Energy Inc.

natural gas due to its similar gas composition and fuel properties. Where we have seen the biggest demand for RNG, however, is as a transportation fuel, due to incentives from California's Low Carbon Fuel Standards (LCFS) program. In 2019, about 40% of natural gas vehicle fuel was sourced from RNG.

While H_2 may be a competitive decarbonization solution for the industrial sector or energy-intensive, high-heat applications, RNG is also attractive for the buildings sector, especially in the residential and commercial space where modification or retrofitting of appliances would not be needed.

***GP&LNG:* With respect to the cost of H_2 projects, do you expect to see more "blue" H_2 projects (H_2 produced from natural gas reforming, with added carbon capture and storage) implemented over the near-term, vs. "green" H_2 projects (H_2 produced from electrolyzers using renewable energy power, with zero carbon emissions), due to the higher cost factor for green H_2 projects at present?**

KW: To enable a low-cost, low-carbon economy, we must expand our supply of H_2. As you noted, there are several technologies to produce H_2, with steam methane reforming (SMR) dominating H_2 production today. When SMR is combined with carbon capture, it enables production of clean H_2. Technologies that we implement to reduce emissions must be cost-effective for our economy and for a diverse set of customers, whether focused on large-scale power generation or serving disadvantaged communities.

Disruptive innovation will be needed to produce a low-cost supply of H_2, regardless of the color or feedstock. As many studies point out, the cost of blue H_2 is significantly lower than that of green H_2, so in the near to medium term, H_2 from natural gas will continue to provide the majority of H_2 supply, and this trend will continue until electrolyzer costs and electricity prices come down. It is also important to note that the impact of policies around tax incentives, production credits and the cost of carbon will further accelerate the supply of clean H_2. We are also exploring the creation of H_2-focused hubs or centers where existing assets and infrastructure can be leveraged and matched with multiple local end-users as a way to reduce costs.

As part of our Hydrogen Network Demonstration in Texas, the project team is also developing a framework for integrating H_2 as a low-carbon fuel within the Port of Houston, which includes plans for production, delivery, transport and use of H_2 to decarbonize the port's industries and operations (**FIG. 1**). The intent is to apply similar frameworks to other areas in the U.S. to expand the role of H_2 in our energy systems.

The global effort to reduce greenhouse gas emissions is driving a need to deploy and develop low-carbon technologies quickly, and the increased use of renewable resources is driving demand for more means to store energy. H_2 offers great versatility that can go a long way toward meeting decarbonization goals across all sectors of the economy. **GP**

Reduce emissions and save energy with an unconventional flare gas recovery system

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An unconventional flare gas recovery system (FGRS) can be designed without a gas compressor to collect the boiloff gas from the ethane tank to the boilers at the utility area. This innovative recovery system will provide significant capital and operating cost savings by eliminating the installation and operation of a gas compressor as part of the conventional FGRS. The FGRS scheme includes the use of a gas ejector with high-pressure motive gas to boost low-pressure ethane flare gas to the intermediate pressure, which is required to return the gas to the boilers at the utility area.

The case study included here explains how the unconventional FGRS was applied at Saudi Aramco's Yanbu NGL fractionation plant to continuously recover approximately 1.1 MMsft^{3}d of valuable C_2+, which is equivalent to 1,961 MMBtu/d in fuel energy savings. The proposed FGRS scheme will also minimize greenhouse gas emissions and provide positive environmental benefits.

Project introduction. Flare systems are essential parts of any oil and gas processing plant. These systems, which essentially consist of flare headers and laterals, liquid knockout drums and flare stacks, serve as one of the last layers of protection for the plant to safely relieve pressure from plant equipment during an overpressure condition. As part of safety requirements, flare headers are normally provided with continuous purging to prevent vacuums within the system, keep air out of the system and prevent possible explosions.

The major component of any conventional FGRS is the gas compressor. It is required to compress the low-pressure flare boiloff gas to a pressure that can return the gas to the process. The recovery gas compressors have recurring maintenance, operating spare and reliability issues, similar to any other rotating equipment in a process plant. It would, therefore, be an attractive and economic venture if the use of a gas compressor can be eliminated from the FGRS without jeopardizing the performance and safety of the system. To this end, a scheme was evaluated using a gas ejector that can provide additional operating flexibility and reliability to the system.

At the Yanbu NGL fractionation plant, the purge gas used is ethane. To ensure no air ingress into the flare headers, a minimum flowrate of purge gas must be continuously maintained for each flare system at the plant. One 100% ethane tank flare system is in use. The system has a flare header of 12 in.–16-in. diameter; therefore, the maximum continuous load of ethane boiloff to flare system is 1.1 MMsft^{3}d. The total flared gas is available to be continuously collected and routed back to the boiler utility area.

The study revealed that it is feasible to recover the continuous flared gas by connecting new piping from the flare system upstream of the flare knockout drum to the boiler utility area, to allow continuous boiloff and utilize it as fuel for the boilers. FIG. 1 shows a schematic of the ethane tank flare system arrangement at the Yanbu NGL processing facility.

The unconventional FGRS scheme was established and carefully evaluated through hydraulic and process simulations, using both in-house programs and proprietary software,[a] as described in the following section.

Ejector-based FGRS. The scheme was developed by utilizing a suitable ejector to collect the 1.15 MMsft^{3}d of continuous flare gas at 0.48 psig, using 0.95 MMsft^{3}d of available high-pressure gas as motive gas. The process scheme was modeled, simulated and confirmed possible, using proprietary software.[a] To this end, a recovery system utilizing high-pressure gas at 380 psig as motive gas—in an ejector to transport the gas from the flare site to the boiler utility area—was established. FIG. 2 shows the calculated flowrates and pressures for the feeds and outlet streams of the ejector. FIG. 3 shows the flow scheme for the ejector-based FGRS.

This flare gas recovery approach is possible based on the fact that there is enough room in the boiler utility area to accommodate the flared gas volume. Flare gas recovery at the plant requires

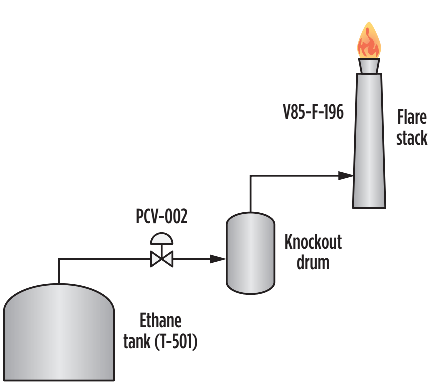

FIG. 1. Schematic of ethane tank flare system at the Yanbu NGL processing plant.

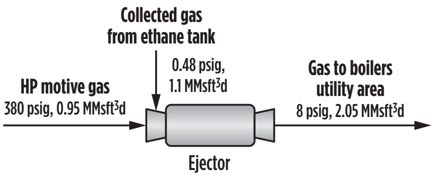

FIG. 2. Calculated flowrates and pressures for the Yanbu FGRS ejector.

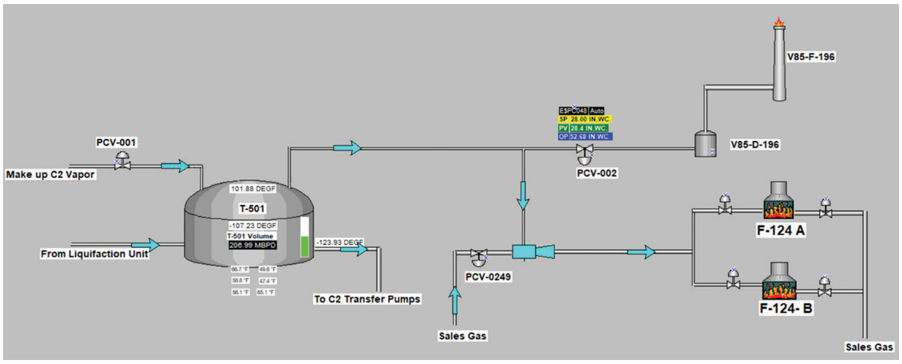

FIG. 3. Flow scheme of ejector-based FGRS at the Yanbu facility.

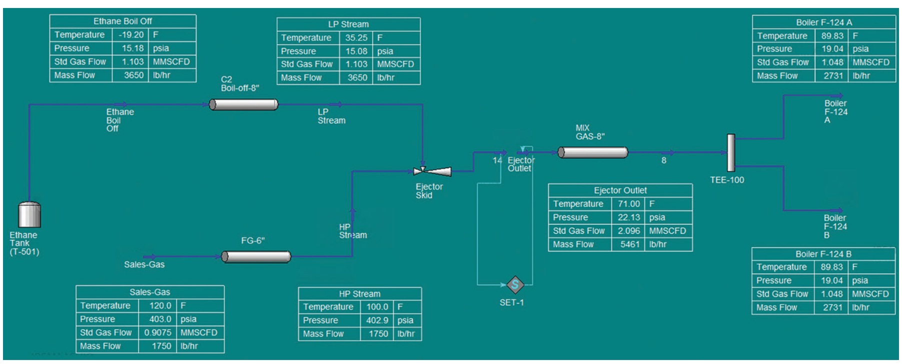

FIG. 4. Ethane recovery system simulation.

only the means to transport the gas from the ethane tank flare system site to the boiler utility area at the gas plant (a total distance of approximately 1.7 km) within the limited differential pressure. Appropriate pipe sizes within the available differential pressures were determined by careful analysis of the hydraulic simulation results. The results show that 2.05 MMsft³d of mixed high-pressure fuel gas and ethane at 17.5 psig will arrive at 8 psig at the utility area, using 6-in. piping.

In the proposed recovery system, the pressure control valve already exists between the flare gas offtake points and the flare knockout drum. This design maintains a slight positive pressure in the flare header and prevents both an undesirable opening condition for the control valve and the release of ethane to the flare system. Whenever the amount of gas released into the flare system exceeds the capacity of the recovery system (1.1 MMsft³d), a pressure control valve on the flare recovery line will act to maintain the flow at 1.1 MMsft³d. The proposed recovery scheme is illustrated by the flow scheme shown in **FIG. 3.**

Simulation results. The ethane recovery system is designed to take ethane from the ethane storage tanks and compress it for firing at 1.5 psig–2 psig and for delivery at approximately 3.7 psig to the two boiler skids.

The ethane recovery system was simulated, using proprietary software[a] to perform the hydraulic analysis and predict the process conditions (**FIG. 4**). Actual pipe lengths for the existing and new pipes are taken from an isometric drawing, to account for the pressure losses from the ethane tank to the boilers at the utility unit. The design flow used to size the recovery system is 0.4 MMsft³d–1.1 MMsft³d, with an ethane composition of 98%.

The results of the hydraulic analysis indicated that new and existing pipes are of adequate size to avoid backpressure on the ethane tank under normal operation, and they are able to deliver the mixed gas stream at a pressure of 3.7 psig to the boiler skids. A sensitivity analysis, including summer and winter conditions, was also run to calculate the system pressure drop. The calculated pressure drop for the 8-in. ethane line from the tank vapor line to the ejector skid inlet is 0.1 psig. The simulation results also validate the pressure drop calculation performed by a third party.

Takeaway. The established FGRS scheme has multiple economic benefits. First, it will recover approximately 1.1 MMsft³d of valuable C_2+, which is equivalent to 1,961 MMBtu/d in fuel energy savings.

Second, the system will operate without any energy consumption or rotating equipment (all installations are static equipment—i.e., no moving parts). The system will utilize energy that would otherwise have been wasted or flared since plant startup.

Third, the flare gas recovery system will improve the reliability and life span of the flare tip, thereby reducing the recurring cost of flare tip replacements. The proposed system will minimize greenhouse gas emissions and provide a positive environmental impact.

Finally, operation of the established FGRS at the Yanbu NGL fractionation plant will provide an operating experience base within Saudi Aramco for other facilities to adopt. **GP**

NOTE

[a] HYSYS

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IRFAN ASHIQ is a Senior Operations Engineer for Saudi Aramco at the Yanbu NGL fractionation plant. He has more than 22 yr of professional experience in process design, operation and commissioning for upstream oil and gas, heavy oil and petrochemicals. Prior to joining Saudi Aramco, he was the Lead Process Engineer at SNC Lavalin in Canada and a Senior Process Engineer at Propak Systems Ltd. in Canada. He holds an MS degree in chemical engineering from the University of Calgary in Canada and a professional certification from the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Obtain accurate NO_X values for strategies to reduce emissions from combustion

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In the process of developing low-nitrogen-oxide-emissions (NO_X) combustion appliances, the request for the volume of NO_X emissions from the tail flame is given in milligrams/kilowatt hour (mg/kWh) in almost all national and regional standards and related certifications. However, the instrument that measures NO_X in the exhaust tail flame of the combustion reports only in ppm or mg/m^3. This requires the calculation of the NO_X in mg/kWh, based on the measured NO_X in ppm or mg/m^3 and related data for these specific combustion systems.

This article summarizes how the combustion industry presently converts ppm to mg/m^3 and introduces a concept for measuring the emission rate of a combustion system. With this concept, a formula can be derived to calculate the NO_X produced by combustion in mg/kWh. The combustion of methane and propane are used as examples in a demonstration of the measured ppm or mg/m^3 concentration of NO_X, along with the the CO_2 or O_2 concentration in the tail flame, to calculate the NO_X emissions in mg/kWh.

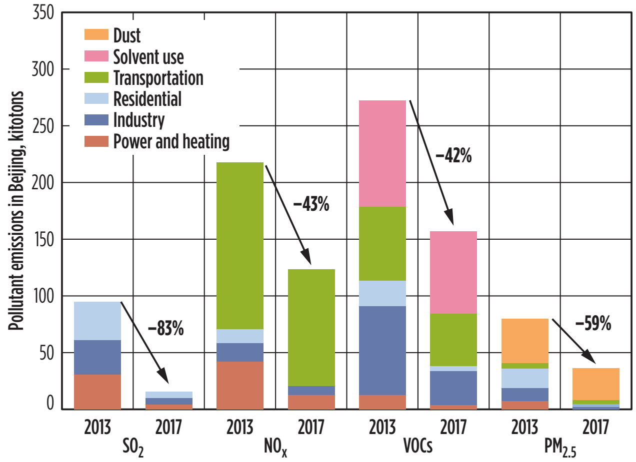
This discussion explains how, when applying various methods to reduce NO_X emissions from the combustion process, the traditional measurement results of NO_2 content (accounting for 5%–10% of NO_X) can give an estimated result. However, to obtain accurate NO_X values, it is necessary to precisely measure NO value, as well as NO_2 value. More accurate measurement of emissions values and amounts aids in emissions reductions for combustion, thereby helping control air pollution.

Incentives for accurate emissions measurement. Immense economic growth in China since the 1980s has resulted in significant air pollution in major cities, which poses a serious threat to public health. However, decades of hard work and investment by the municipal government have paid off, resulting in a dramatic reduction in air pollution.

The Beijing 2013–2017 Clean Air Action Plan[1] is the most comprehensive and systematic pollution control program put into practice in Beijing to date. From 2013–2017, emissions of SO_2, NO_X, volatile organic compounds (VOCs) and particulate matter (PM2.5) decreased by 83%, 43%, 42% and 55%, respectively (FIG. 1, left). However, during the same time period, changes in major air pollutant emissions in the areas surrounding Beijing (including Tianjin, Hebei, Henan, Shandong, Shanxi and Inner Mongolia) were not as desirable (FIG. 1, right). Other areas in the country face the same problem. To clean China's air supply, numerous issues must still be addressed; this article was written with this task in mind.

NO_X emissions caused by combustion are an important factor in the formation of air pollution and smog.[2–5] NO_X, which comprises mainly NO and NO_2, is the general term for a group of highly reactive gases. Most nitrogen oxides are colorless and tasteless; however, in many cities or densely populated areas, the pollutant NO_2 and other particles in the air often form a reddish-brown smog or haze.

When NO reacts with O_2 in the air under sunlight, ozone



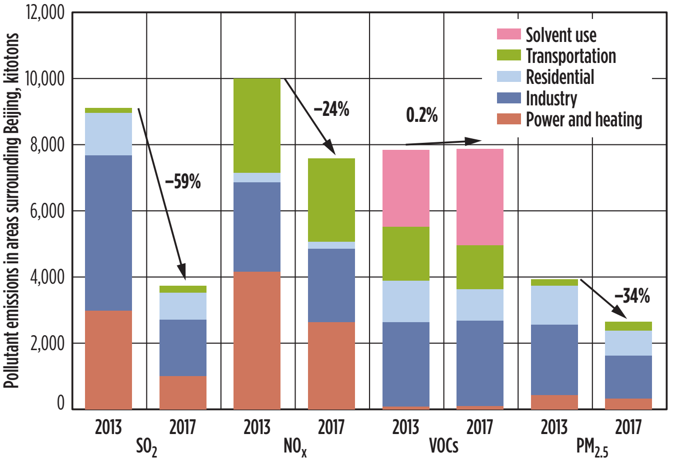


FIG. 1. Changes in anthropogenic emissions of SO_2, NO_X, VOCs and PM2.5 in Beijing, 2013–2017 (left). Changes in major air pollutant emissions in the areas surrounding Beijing (including Tianjin, Hebei, Henan, Shandong, Shanxi and Inner Mongolia), 2013–2017[1] (right).

is produced near the ground. Ground-level ozone has an adverse effect on the respiratory system, causing lung cancer and affecting agricultural production. NO_X also reacts to form nitrate particles and acidic aerosols, which can cause respiratory problems. When NO_X reacts with water to form nitric acid, it causes acid rain and deterioration of water quality. Additionally, acid gases and airborne particles can cause reduced visibility and reduced air quality.

Many standards, both at home and abroad, restrict NO_X emissions and outline specific regulations—e.g., Beijing boiler air pollutant emissions standard DB11/139-2015,[6] Chinese gas heater standard CJT113-2015,[7] and European CE standard for infrared heaters BSEN 416-1.[8] In all of these standards, the emissions reporting is given in mg/kWh. Many customers require manufacturers to provide NO_X emissions data in mg/kWh when purchasing combustion-related appliances. For example, in Beijing, the NO_X emissions from a newly built boiler cannot be greater than 100 mg/kWh.

However, almost all instruments that measure the tail flame of a burner offer a reading of NO_X only in ppm or mg/m^3.[9] Using the measured NO_X data (in ppm or mg/m^3) to calculate the NO_X produced by the combustion system (in mg/kWh) is an important calculation, but many relevant documents and standards offer complicated conversions or, conversely, very simple tables[8,9] that do not explain the theoretical basis behind the conversions. Many standards simply do not mention the conversion method, causing confusion and difficulty for the engineering community. This article describes a simple, accurate calculation method that was derived in the process of developing low-NO_X heaters.

Background on conversion of ppm to mg/m^3. The engineering and academic communities have held recent discussions on the conversion of ppm to mg/m^3.[10] A brief overview of the conversion history follows for those readers seeking background information.

Ppm is often used to express concentration, such as mass ppm concentration or volume ppm concentration (i.e., ppmv). Ppmv is a common way of expressing gas phase concentration. Gas is miscible and, generally speaking, once equilibrium is reached the gas is homogeneous, meaning its components are evenly mixed together. In SI units, the volume for this gas is cubic meters (m^3). If the gas mixture is divided into components and the concentration of one component in the gas mixture is assumed to be 1 ppm, and if the mixture is 10^6 m^3, then the gas of this component should be 1 m^3. This results in 1 m^3 of a certain component, or 10^6 m^3 for a mixture = 1 ppm.

Eqs. 1 and 2 are derived from the ideal gas law (for gases at lower pressures):[11]

$$PV = nRT \tag{1}$$

$$PVi = n_iRT \tag{2}$$

Here, P is the pressure (in pascal); V is the volume (m^3); n is the number of moles (proportional to the number of molecules) of all components; R is a constant, called the universal gas constant, with a value of 8.3143 joules/K mole; T is the Kelvin (K) temperature; V_i is the partial volume of the gas component i; and n_i is the molar number of gas component i.

Eqs. 1 and 2 can be rewritten, as shown in Eqs. 3 and 4:

$$V = nRT / P \tag{3}$$

$$V_i = n_iRT / P \tag{4}$$

Next, a certain trace gas in the mixed gas can be considered. Assuming that V_i is the volume of the trace gas and V_T is the total volume of the mixed gas, both sides of the second equation are divided by V_T, which gives the concentration of the trace gas that can be expressed as a volume ratio (Eq. 5):

$$\frac{V_i}{V_T} = \frac{n_iRT}{PV_T} \tag{5}$$

Then, x_i can be used as the concentration of the trace gas component i in ppm (Eq. 6):

$$\frac{V_i}{V_T} = 10^6 x_i \tag{6}$$

Using X_i as the mass concentration of component i in mg/m^3 and assuming the molar weight of component i is M_i (g/mole) gives Eq. 7:

$$10^6 x_i = \frac{n_iRT}{PV_T} = \frac{(n_iM_i)}{V_T}\frac{RT}{M_iP} = \left[10^3 X_i\right]\frac{RT}{M_iP} \tag{7}$$

When the low index i in these equations is neglected, Eqs. 8 and 9 result:

$$X = x(MP \div RT) \times 10^3 \text{ mg/m}^3 \tag{8}$$

$$x = X(RT \div MP) \times 10^{-3} \text{ ppm} \tag{9}$$

Note that the concentration x is in ppm, the unit of concentration X is in mg/m^3, and M is the molecular weight of the trace gas concerned (g/mole). Eqs. 8 and 9 have been generally accepted by the academic and engineering communities, and literature[10] describes them at constant temperature.

Simple calculation procedures are also provided on relevant websites in America and Europe. For example, on some sites,[12,13] the only required inputs are the value of the concentration x or X of a certain gas at atmospheric pressure and 25°C, along with the molecular weight of the gas. The program will immediately give the value of X or x under the corresponding conditions. In addition to the calculation,[12,13] users can change the gas temperature and pressure inputs.[14] The molecular weight of NO_2 is 46.01 g, and the molecular weight of NO is 30.01 g; therefore, at a temperature of 20°C (293.15 K) and 1 atm, 1 ppm NO_2 = 1.91 mg/m^3, and 1 ppm NO = 1.25 mg/m^3.

In the general combustion system, NO_2 in tail flame accounts for approximately 5%–10% of NO_X and NO accounts for about 90%–95%.[15–18] When NO_2 accounts for 10% of NO_X, the average molecular weight of NO_X can be calculated as M = 31.61. Under the same temperature and pressure conditions as the previous calculation, for NO_X, 1 ppm = 1.29 mg/m^3.

Calculation of NO_X in mg/kWh for a combustion system. For a combustion system, the NO_X concentration in the tail flame can be measured in ppm or mg/m^3. However, the NO_X emission in mg/kWh dictates how many mg of NO_X are produced in a combustion system when it releases 1 kW in 1 hr. This means that NO_X in mg/kWh is not only related to the NO_X concentration in the tail flame, but also to the volume flowrate of the tail flame and the power produced by the combustion system.

The emission rate, E, of pollutants like NO_X from a combustion system must first be defined. A combustion system is used to generate certain power or heat, thereby producing pollutants. The higher the power is generated by the system, the more pollutants are produced. Since all pollutants are discharged to air through the tail flame, the total mass flowrates of the pollutants can be calculated from the volume mass concentration of pollutants, mg/m^3, and the volume flowrate of the tail flame.

E can be defined for a certain pollutant as the total mass flowrate for this pollutant in the tail flame, divided by the power generated by the combustion system. This E is listed in mg/kWh. In this article, E is used for emission of NO_X, but it also can be used for emission of other pollutants, such as CO, SO_2, SO_3, etc.

Now the volume flowrate of the tail flame of a combustion system can be calculated. For the sake of simplicity, it is assumed that the concentrations of CO, NO, NO_2, SO_2, etc. in the combustion products are negligible compared to the concentrations of O_2, CO_2, H_2O and N_2. At the same time, it is assumed that there is no water vapor condensation, at least at the measurement point in the tail flame generated by the combustion system. Based on the authors' many years of experience in the research and development of various types of heaters in the U.S. and China, these two assumptions should be valid for general combustion systems, such as infrared heaters, unitary heaters, home heaters, etc.

In air, the composition of O_2 is 20.95%, while N_2, Ar and other elements make up 79.05% in volume.[16] If the volume flowrate of O_2 is 1 for a combustion system, then the ratio of the volume flowrate of N_2, Ar, etc. to the volume flowrate of O_2 is 79.05 ÷ 20.95 = 3.77. Since gas components like Ar do not participate in the reaction, for the sake of brevity, only N_2 is used to represent these components.

Consider the combustion of methane (Eq. 10):

$$CH_4 + 2O_2 = CO_2 + 2H_2O \tag{10}$$

If the reaction or combustion occurs in air, then Eq. 11 can be used:

$$CH_4 + 2(O_2 + 3.77\,N_2) = CO_2 + 2H_2O + 7.54\,N_2 \tag{11}$$

If V_a represents the volume rate of CH_4 consumption, then when the reaction product is cooled to normal temperature (assuming that the water vapor is not condensed at this time), the volume rate of the tail flame generated will be $V_a + 2V_a + 7.54V_a = 10.54V_a$. According to combustion theory,[18] to avoid significant production of CO and carbon, there should be a certain excess of O_2 in combustion systems. Considering this, the reaction formula in Eq. 11 can be written as shown in Eq. 12:

$$CH_4 + (2 + y)(O_2 + 3.77N_2) = CO_2 + 2H_2O + 7.54N_2 + y(O_2 + 3.77N_2) \tag{12}$$

It is assumed that $y(O_2 + 3.77N_2)$ is O_2 and corresponding N_2 in the excess air. If V_a is the rate at which the volume of fuel gas CH_4 is consumed, then the volume rate at which the reactants disappear and the volume rate of the products generated in the tail flame (when cooled to room temperature) can be calculated as shown in Eq. 13:

$$V_a + 2(V_a + 3.77V_a) + y(V_a + 3.77V_a) \text{ and}$$

$$V_a + 2V_a + 7.54V_a + y(V_a + 3.77V_a) \tag{13}$$

Therefore, the total flow of the tail flame produced by the combustion system will be $(10.54 + 4.77y)V_a$.

The y in Eqs. 12 and 13 can be obtained from the concentration of CO_2 measured in the tail flame or the concentration of O_2 measured. First, the measured CO_2 concentration is measured, as shown in Eq. 14:

$$CO_{2measured} = \frac{V_a}{(10.54 + 4.77y) \times V_a} = \frac{1}{10.54 + 4.77y} \tag{14}$$

The result is applied to Eq. 15:

$$y = \frac{\dfrac{1}{CO_{2measured}} - 10.54}{4.77} \tag{15}$$

In this way, the volumetric flow of the tail flame can be represented as shown in Eq. 16:

$$\text{Volume flowrate of the tail flame} = 10.54V_a + 4.77yV_a = (1 / CO_{2\,measured})V_a \tag{16}$$

The power of the combustion system is generated by the consumption of CH_4 at a specified flowrate (V_a) and heat of combustion (HV), with the power of combustion = HV × V_a. Since the mass emission rate of NO_X is X, Eq. 17 is used to calculate E:

$$E = (\text{Volume mass concentration of emission of } NO_X \times \text{Volume flow of tail flame}) / \text{Power of combustion system} \tag{17}$$

Substituting Eq. 16 and the power of combustion (HV × V_a) into the formula results in Eq. 18:

$$E = X / (CO_{2measured} \times HV) \tag{18}$$

Using the same procedure, from the measured O_2 concentration ($O_{2measured}$), E can be found, as shown in Eq. 19:

$$E = \frac{10.54X}{(1 - 4.77O_{2measured}) \times HV} \tag{19}$$

In Eq. 19, HV can be the low-combustion value (LHV) of CH_4 or the high combustion value (HHV) of CH_4, which is determined by the condensation of water vapor in the tail flame. The authors suggest using the LHV because it is assumed that the measurement is conducted before the water condensation,[19] resulting in Eq. 20:

$$LHV = 35.9 \times 10^6\, J/m^3 = 35.9 \times \frac{10^6 J}{m^3} \times \frac{3{,}600 \text{ sec}}{3{,}600 \text{ sec}} = 9.97(kWh/m^3) \tag{20}$$

It is known that 1 hr = 3,600 sec, and 1 joule/sec = 1 W. If pressure is assumed at 1 atm and temperature is assumed at 20°C (293K), and if $X = 1.25\,qx$ mg/m^3 is used, then Eqs. 21 and 22 can be calculated:

$$E = (0.125x)q \div CO_{2measured} \text{ mg/kWh} \tag{21}$$

$$E = \frac{1.32xq}{1 - 4.77O_{2measured}} \text{ mg/kWh} \tag{22}$$

Here, $q = M_{NOx} \div M_{NO}$.

For propane (C_3H_8) combustion, the reaction shown in Eq. 23 occurs:

$$C_3H_8 + 5O_2 = 3CO_2 + 4H_2O \tag{23}$$

If the reaction or combustion occurs in air, then the reaction shown in Eq. 24 occurs:

$$C_3H_8 + 5(O_2 + 3.77N_2) = 3CO_2 + 4H_2O + 18.85N_2 \tag{24}$$

Using the same procedure as that for methane and taking the LHV of propane,[19] LHV = 25.9kWh, Eqs. 25 and 26 are calculated as follows:

$$E = \frac{0.145xq}{CO_{2\text{measured}}} \text{ mg/kWh} \tag{25}$$

$$E = 1.25xq[1 + 4.77O_{2\text{measured}} / (1 - 4.77O_{2\text{measured}})] \tag{26}$$

Here, $q = M_{NOx} \div M_{NO}$.

In recent years, to eliminate emissions of NO_X to the environment, countries around the world have been developing low-NO_X combustion technologies.[4,5,20,21,22] NO_X emissions reduction is important for decreasing the level of NO_X released into the atmosphere by combustion activities. When NO_X reduction strategies are used, the ratio of NO to NO_2 may change, and so the traditional calculation of NO_2 content accounting for 5% of NO_X can no longer be used.

At present, the value of NO_2 can be even greater than 50% of the total NO_X emission. In this scenario, it is important not only to accurately measure the value of NO, but also to accurately measure the *amount* of NO_2. Additionally, since NO_2 is very soluble in water, if condensation of water vapor occurs in the exhaust smoke, as much as 50% of NO_2 will be dissolved into the condensed water from the gas phase, which greatly affects the reading. Therefore, it is necessary to ensure that water vapor does not condense during the measurement.

Takeaway. This article summarizes the conversion method between ppm and mg/m^3 presently used in the engineering world. It also explains the development of a method to calculate NO_X in mg/kWh from combustion systems that use methane or propane as fuel. This method can be used to calculate emissions of other pollutants, such as CO and SO_2. **GP**

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Evolution and innovation for an increasingly dispersed LNG market

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The LNG industry must adapt to changing market conditions to grow, thrive and reach its full potential. LNG consumption and commercial patterns are in a state of change, yet the production facilities and systems supplying the markets—as well as the financing institutions that underpin their existence—are proving glacial in their speed to react.

The advent and opportunities for the use of LNG as a fuel for factories, off-grid power plants, long-haul road transportation, locomotives, harbor and nearshore service vessels, ferries and international marine shipping are creating a market that is more diverse and dispersed than the traditional, large-volume, point-to-point structure forming the basis for much of the existing global LNG value chain.

This new market also exhibits greater elasticity in demand than contemplated in traditional sales-and-purchase agreements and financing conditions. LNG must overcome some challenges to achieve its potential as the preferred clean hydrocarbon fuel and a complementary solution to increased renewables penetration. One hurdle is that LNG production and loading, product transportation and delivery infrastructure must introduce systems that enable LNG to reach this increasingly diverse and dispersed market, or else energy consumers will turn to other sources out of necessity. Additionally, financing of these projects must consider the increased variability/seasonality of demand, as well as offtake by multiple smaller customers with corresponding smaller balance sheets and less established (if any) credit credentials.

Despite these challenges, significant opportunities exist. Typical (non-pandemic) global diesel fuel prices are on the order of \$20/MMBtu–\$30/MMBtu, while current large-bulk LNG deliveries are available at well under half that price, proving a strong economic basis for growth as a replacement for diesel and other distillate fuels, in addition to the reduced emissions incentive delivered by LNG. The total global marine fuel energy consumption alone approaches the global LNG production volume energy, which itself is less than 3% of total global energy consumption. A growing market for smaller LNG ships, transport barges, ISO containers and LNG distribution trucks has emerged, and additional innovative development is necessary in the future. A substantial growth market exists for LNG, but only if the industry can develop and finance a supply infrastructure to meet this evolutionary opportunity.

LNG market discussion. The size of the prize available to the LNG industry for expanding into a broader slice of the global energy market is substantial. Total global energy consumption in 2019 was 583.9 exajoules[1] (an exajoule is 1,018 joules, an unimaginably large number—2019 usage was the energy equivalent of 4.431 T gal of gasoline), which was a nominal 1.3% increase from 2018. This represents the total of natural gas, oil, nuclear, coal, hydropower and renewables. Of this amount, natural gas provided 24% of global energy in 2019, in third place behind oil and coal.

LNG itself represents nominally 12% of global natural gas, or under 3% of global energy—i.e., while LNG garners a lot of attention, it actually represents a very small fraction of the world's energy consumption, providing an excellent opportunity for significant growth.

The unique characteristics of LNG must be considered when seeking to capture these growth opportunities. First, the volumetric energy density of LNG is low. Compared to diesel or fuel oil, LNG carries only about 58% of energy per unit volume. Consequently, to carry the equivalent amount of diesel fuel, a vehicle would require a substantially larger LNG fuel tank or be faced with the need to make more frequent refueling stops.

Using compressed natural gas (CNG) in lieu of LNG worsens the situation, since the energy density of CNG (3,600 psi) is only about 25% of that for diesel, or less than half of LNG's energy density. However, on a weight basis, the energy density of LNG is actually double that of diesel, so when weight is critical, LNG may provide advantages.

Fuel temperature and metallurgy are also important considerations; at –160°C (–256°F), LNG must be stored in insulated containers suitable for cryogenic conditions (stainless steel or aluminum), and the LNG must be vaporized and heated prior to use. Fuel storage duration is another consideration; conventional liquid fuels (diesel, fuel oil, gasoline, aviation fuels) can be stored indefinitely with suitable care. LNG storage will eventually need to vent boiloff gas, as LNG cannot be maintained in the liquid state without external or internal refrigeration. The amount of time that LNG can be stored prior to venting depends on the container, and ranges from 70 d–80 d for large ISO containers[2] to as little as 4 d for small cylinders.

In addition, LNG is generally not a pure component fluid, and the lightest of its components (nitrogen, methane) tend to selectively boil off first, causing the remaining liquid to concentrate the heavier components (ethane, propane, butane). In time, this can cause the composition of the LNG to go off-spec compared to user requirements, and must be carefully managed.

LNG has long been a "big-time" business: big owners (national and interna-

tional oil companies), big plants (millions of metric tons of production yearly), big ships (1,000-ft long), big users (public utilities) and big money enable it to happen. More recently, a few entrepreneurial companies have tried a different approach to the LNG market, building much smaller, fuels-scale projects and shipping their product in small containers to the end users, with good success. Some projections[3] are that more than one-third of global LNG production growth over the next 4 yr will come from U.S.-based small-scale (< 2 metric tpy) newbuild facilities.

However, despite this initial and projected success, these small operations have grown slowly. Challenges faced by producers and distributors of small quantities of LNG include:

- Energy efficiency—Modern, full-scale LNG production plants consume nominally 8% of their feed gas as fuel. Small-scale plants have been required by economic necessity to minimize CAPEX and, as a result, tend to be much less energy efficient, consuming 12%–20% of feed gas as fuel (or equivalent imported power).
- GHG signature—With lower energy efficiency comes higher carbon dioxide (CO_2) emissions (whether directly or indirectly, via imported power). The world is increasingly focused on achieving best available technology with regard to CO_2 emissions. The CO_2 savings for the end user are substantial, but production emissions are relatively high compared to achievable values.
- Material handling—It is challenging to move substantial quantities of liquids in relatively small containers. A small, 2-MMtpy LNG production facility shipping in conventional 155,000-m^3 carriers would require 28 ships/yr, or about one every 2 wk. Moving this same small plant capacity in the biggest ISO containers [nominally 40-ft (43-m^3) long] would require more than 100,000 containers/yr to be filled, transported, emptied and returned, or 280 containers/d.
- Shipping costs—A significant portion of shipping costs are independent of volume. Moving LNG long distances in small quantities disproportionately increases the unit cost, making the small-scale product economically unattractive outside of regional deliveries. Many small-scale facilities would be unable to shoulder the burden of infrastructure costs to accommodate large-scale ship-loading operations and are restricted to regional markets.[2,3]
- Export port priorities—Large export facilities needing to move substantial quantities of LNG may be unable to make sufficient loading windows available for small-scale ships and barges and still load their annual commitment of cargoes.
- Security of supply—Today, LNG in small quantities is not widely available from multiple parties. With diesel or fuel oil, production issues at one supplier can readily be accommodated by others. In the present LNG market, if a single, dedicated, small LNG ISO container or barge-loading facility were to become temporarily unavailable (i.e., due to weather, maintenance or unplanned outages), the receiving facility could be seriously challenged to access replacement suppliers in the short term.
- Financing—This is a significant issue; historically, funding for the substantial costs to underpin the development of LNG liquefaction infrastructure has been underpinned by long-term (20-yr), take-or-pay contracts with credit-worthy buyers. The small-scale market can be much more diverse, seasonal, variable in demand and comprise buyers without access to investment credit ratings. Financing for small-scale facilities will require a different, more flexible model.

The key to success for small-scale LNG lies in finding a pathway that alleviates these substantial challenges while still being positioned to take advantage of the growing, and increasingly diverse and dispersed LNG consumer market opportunities. This pathway will focus on logistics—finding the solution that enables the capture of big-project economies of scale on the production and transportation end, coupled with small-project innovation and flexibility on the consumer end through the evolution of the LNG value chain, supported by financial backing that can enable the development.

Economic drivers. On a fundamental energy basis, classic, large-scale LNG competes commercially with coal. Despite the substantial environmental advantages that natural gas provides compared with coal (e.g., 50% lower CO_2 emissions per unit volume of energy, lower NO_X and SO_X, vastly reduced particulate emissions, elimination of Hg emissions, much less invasive production), coal remains in high demand due to low cost and previously invested capital, representing 27% of global energy production in 2019.[1]

The challenge is that as renewables grow rapidly in the market, they tend to push out the more expensive fuels first, regardless of the environmental profile. Small-scale LNG competes more directly with oil, specifically with diesel fuel, fuel oil and ship bunker. In this market, LNG holds the economic advantage. Even in a low-oil-price market, such as that seen during most of the ongoing COVID-19 pandemic, global average diesel prices are higher than global average natural gas and LNG prices.[4] This makes the small-scale LNG market an attractive economic opportunity, if the challenges can be effectively solved.

Market opportunities. Renewable energy is now emerging as the energy source of choice in a world increasingly concerned with greenhouse gas emissions and climate change. As noted above, in many markets including Europe and Japan, renewables have had more success in displacing natural gas than coal, driven more by economics than by environmental concerns, despite the better fit of natural gas in reacting to variations and sudden changes in renewable energy production.[1,4]

Going forward, the growth of LNG and natural gas in the traditional markets of large power generation facilities, industry, commercial and residential heating will be increasingly challenged by the accelerating growth of wind and solar power. Small-scale LNG operating in different market dynamics that compete more directly with liquid fuels is less challenged by renewables in some key markets—this generates opportunities. Considerations associated with these market opportunities are discussed here.

Marine. The global shipping industry consumed 4.36 MMbpd of fuel oil/bunker fuel in 2019,[5] equivalent to 200 MMtpy LNG (56% of 2019 LNG

production volume). Although low in absolute numbers, an increasing number of ships capable of burning LNG as fuel are under construction and entering operations, led by the cruise ship industry, European manufacturers and container ships. There are nominally 90,000 total ships in the global fleet, with 60,000 plying international routes. Ships consume 20 metric tpd–80 metric tpd of fuel oil; for a very large crude carrier (VLCC) traveling from the Middle East to Japan, this typically amounts to \$2 MM–\$2.5 MM for the 25-d voyage.[6] The global average very-low-sulfur fuel oil (VLSFO) price for early-November 2020 delivery was \$355/metric t, or \$9.60/MMBtu. Even at COVID 19-induced depressed fuel prices, LNG is economically attractive.

Availability of LNG at ports to support bunkering is growing, but still limited in a classic "chicken-or-egg" scenario. A total of 96 global ports claim to have access to LNG, but only 12 presently have operational LNG bunkering ships, with another 27 of these ships on order.[5] **FIG. 1** shows global ports with bunkering access.[7]

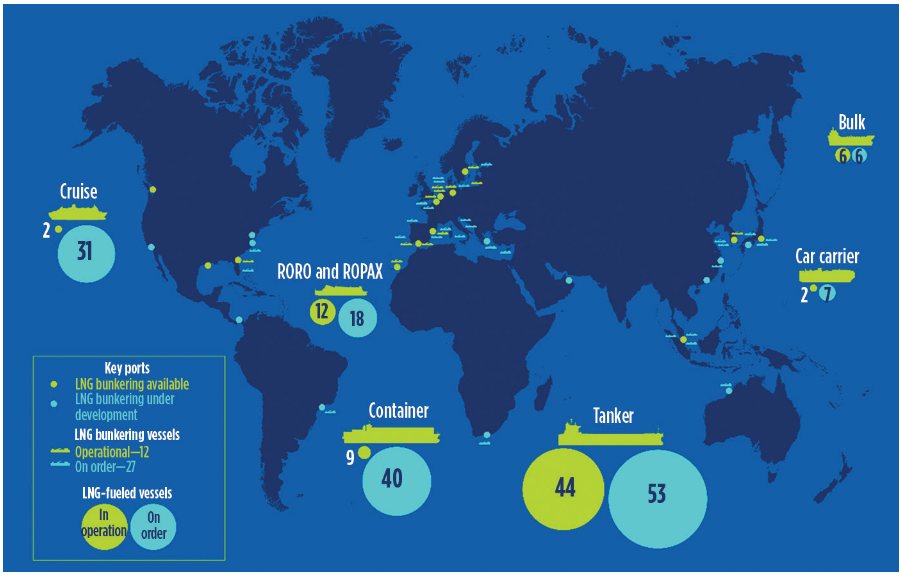

FIG. 1. Global ports with bunkering access.[7]

Regional shipping/port services. LNG bunkering for regional shipping is more straightforward to manage, as the ships can return to the home port for refueling and not be dependent on the availability of infrastructure at other locations. Potential users include passenger and car ferries, offshore service vessels, regional barge shipping and harbor/river tugs. Port service vessels with tight quarters below the waterline (i.e., tugboats) may be challenged for fuel tank space in retrofit designs. Economics strongly favor diesel conversions based on the relative cost of marine liquid fuels vs. LNG.

Long-haul trucking. LNG is a premium fuel for long-haul trucking. On a heat basis, it is less than half the price of diesel (see above) and enables reduced maintenance costs per numerous published reports. Trucks generally have the room to accommodate the larger volumetric storage space requirement, while the weight of the fuel itself is lower. Daily usage is high, such that heat leak and boiloff management are not an issue.

The primary limiting issue for conversion is limited access to LNG, which is not universally available, and the installation of more truck filling stations has been stymied by the lack of converted trucks to purchase the LNG. Steps are being taken to improve this—for example, Louisiana has established an Alternative Fuels Corridor program in support of such efforts.[7]

Commercial transportation. The city of Houston, Texas experimented extensively with the use of LNG-powered city buses in the early 1990s, but reverted to diesel due to design flaws in the fueling system. Houston is now successfully increasing its use of compressed natural gas (CNG) in the city bus fleet. Any type of regional commercial transportation (metro buses, school buses, package delivery fleets, consumer beverage delivery trucks, etc.) that return to a home base daily are well suited for utilization of LNG or CNG, as fuel can be made available at their home base and the vehicles are large enough to adequately store the needed volumes of fuel.

Personal vehicles. Smaller, personal vehicles do not lend themselves to direct use of LNG or CNG due to the limited space available and the lower fuel volumetric energy. Globally, the personal vehicle fleet is moving in the direction of electrification, rather than gasification.

Trains. Locomotive use of LNG is presently very limited, with one application in the U.S. on the Florida East Coast Railway. Locomotives are well-suited to LNG use, with space available for long-haul storage and a near-continuous use profile. Availability of the fuel at terminal locations is the most significant challenge.

Off-grid power stations. These stations represent a prime potential area of growth for LNG if the logistics associated with fueling them reliably can be established. These stations range from micro-scale power plants (as small as 100 kW to feed a remote village or a large ranching operation) through small-scale (5 MW) up to moderately large-scale facilities (> 250 MW). These types of facilities tend to be sited in relatively isolated locations, on islands (the Caribbean, Asia) and upriver, and presently operate on diesel oil delivered by truck or barge. The favorable economics outlined in shipping also apply here, provided that cost-effective fuel supply transportation can be established.

Off-grid manufacturing/farming. Similar to off-grid power stations, and sometimes integrated with them, large industrial and agricultural energy consumers generally use diesel oil, with some global regions (particularly China) using coal, and others (U.S. farms) making extensive use of propane or LPG. Most diesel and coal facilities represent potential conversion to LNG, but they tend to be small consumers (challenging logistics) and intermittent consumers (challenging storage of LNG). Supplying LNG into common, local/regional, short-pipeline distribution systems may be part of a workable solution.

Home heating/cooking, others. This market is not viewed as prime for expanding LNG usage. Small storage systems have been developed and distribution models have been tested, but unless a regional/neighborhood piping system

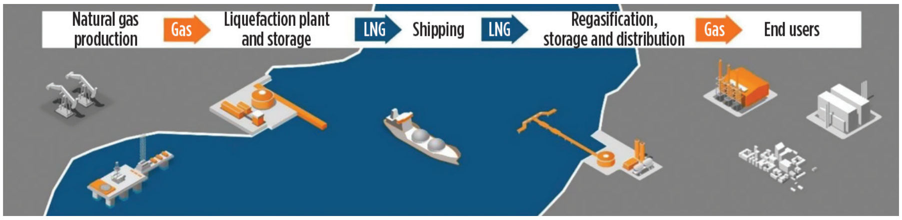

FIG. 2. A classic LNG value chain.[10]

is utilized, it is impractical to achieve this small of a scale for distribution and usage of LNG, primarily due to the limited storage life of LNG before boiloff gas must be managed.

Aircraft. The CO_2 greenhouse gas signature of aircraft has generated significant attention, with 1,000 metric tpy of CO_2 emissions and up to 5% of global warming attributed to the aviation industry (2018 figures[8]). Russia, Boeing and MIT have performed research on the topic of using LNG and natural gas to fuel aircraft.[8] A 2015 study[9] determined that, in addition to environmental and fuel cost advantages, LNG as a fuel increases airframe space needed for fuel but decreases fuel system weight. LNG also provides a means to support thermal management of sophisticated electronics systems. Overall, aircraft looks like an opportunity for 2050 and beyond.

The LNG value chain. Solving the small-scale logistics value chain puzzle will be key to maximizing access to markets for LNG in the future. The classic, large-scale LNG value chain developed in the 1960s is well known. It involves extraction and liquefaction of stranded gas assets in large-scale export facilities; large, dedicated LNG carriers delivering the gas to land-based receiving terminal ports; regasification; and the use of pipelines to carry the gas to nearby, large-scale power plants and into national grids.

The massive infrastructure development costs associated with the elements of this chain are underpinned by long-term, take-or-pay contracts with highly credit-worthy offtakers to enable financing. In today's markets, these investments can run into the tens of billions of U.S. dollars and, subsequently, require substantial economies of scale to create favorable economics. Most recent initial launch capacities of projects have generally been in the range of 10 metric tpy–15 metric tpy (i.e., Cameron, Freeport, Sabine Pass, Calcasieu Pass, Gorgon, Ichthys, Wheatstone, Asia-Pacific LNG, Gladstone, Queensland Curtis) with a couple of smaller facilities at brownfield U.S. import sites at 2.5 metric tpy–5 metric tpy (i.e., Elba Island, Cove Point).

A classic LNG value chain is shown in **FIG. 2.** The value chain needed to support a small-scale dispersed market is substantially different and more complex, both logistically and economically. The ideal small-scale production facility may not need to be small, but it must still be capable of supporting the small, dispersed delivery market.

Built large, such a facility can take advantage of the economies of operational and energy efficiencies inherent in bigger facilities. A large-scale production plant linked into multiple logistics chains, or multiple branches of a single initial chain, can be positioned to serve all markets efficiently and still leverage traditional financing.

Small scale. Small-scale LNG trucking from source to consumer has been demonstrated as economic if good roads are available and the transport distances are in the range of up to 300 mi each way. If markets are relatively close in distance (nominally 500 mi–1,000 mi or less), point to point, at or near ocean ports, and the intervening seas are not frequently subject to rough conditions, then barge transport of LNG is feasible. The advantage to barges is that they are relatively inexpensive, have a shallow draft, and LNG ISO containers can be carried safely on deck or dedicated LNG barges can be utilized. Small-scale U.S. exports have been following this route for services to the relatively close Caribbean region.[10]

Alternately, small (nominally 30,000-m^3) shuttle tankers are also used, requiring deeper draft and more sophisticated loading systems but accommodating heavier seas and multiple port stops. This approach has been used for distribution of small quantities of LNG to Scandinavian ports. Rail transport has been used successfully in Japan for 20 yr[11] and is just now emerging as a permitted means in the U.S.

Large-scale/small-scale integration of traditional, large-scale LNG production and/or receiving facilities with smaller regional demand locations is expected to represent an efficient way to service this growing market without many of the constraints present in the emerging small-scale production market (e.g., energy efficiency, limited market reach).

This integration can be accomplished in at least two basic ways. The first way is the addition of small-scale export facilities (trucks, ISO tanks, barges, small carriers) to traditional, large-scale export plants. These facilities must be segregated from the primary, large ship loading docks to enable the plant to benefit from the small-scale sales without impeding the major volume shipments. The second way is the addition of small-scale redistribution facilities at the large-scale receiving facilities to enable re-export into regional markets. The potential to see transition exists, with a small, dedicated import market developing initially, eventually growing into a regional redistribution hub.

Overall, this integration of the successful and financeable large-scale export and import facilities with ongoing small-user supply at both ends, coupled with hub-and-spoke systems, represents a viable future to reach the increasingly diverse and distributed consumer market potential.

A final word—safety first. Traditional LNG projects throughout the industry maintain an excellent safety record as part of the backbone of reliable energy supply. To maintain this excellence into a more diverse and dispersed market will require purposeful effort. Smaller facilities may not have the focus on training and maintenance that has been embedded into world-scale facilities. Revenue levels may not support dedicated safety staffing, and the nature of the transport, storage and use means a greater degree of manual handling (truck movements, hose connections and disconnects, large numbers of small containers).

NFPA 59A does a good job of addressing both small-scale and large-scale LNG. The parties responsible for design and operations must ensure that adequate hazard identification, analysis and mitigation steps are applied. Design elements, remote

operations and other digital supported solutions can minimize risk exposure and incident severity. With the transition of the retail gasoline market to self-service in the late 1960s and early 1970s, millions of motorists were able to demonstrate that properly designed fueling systems could be used safely,[11] despite initial concerns.

Takeaway. The global energy market is expanding, and natural gas/LNG can play a significant role in meeting these growth needs with a clean-burning fuel that can support expansion, displace other hydrocarbon fuels with a higher emissions profile, and support the transition to a greater penetration of renewables while maintaining security and stability of supply. Much of this growth will happen in a more diverse and dispersed market than has traditionally been served by LNG.

Consequently, market parties must adapt their operations and logistics profiles to align with the changing market to capture the greatest market share available. Developing methods of delivering LNG that benefit from the best attributes of both large- and small-scale facilities will be a key element in this success. **GP**

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Mitigate fouling in process units via advanced analysis

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Fouling, or the undesired accumulation of solid material on a surface, is an increasingly prevalent and challenging problem in processing plants across many industries. As plants move to reduce costs, contaminated feedstocks and ineffective process protection lead to higher fouling rates and associated problems. The costs associated with fouling problems have been estimated at more than \$4.37 B/yr in the U.S. alone in 2019.

Filter plugging and reduced lifetime, reduced heat transfer in heat exchangers, column packing obstruction, and reduced throughput are a few of the harmful effects caused by fouling, in addition to under deposit corrosion. Plants must maintain low costs and high throughput to achieve profitability; therefore, the need for root-cause analysis and cost-effective fouling solutions is critical. Several different techniques, including advanced analytics and expert troubleshooting, can be utilized to mitigate fouling, depending on the nature of the situation.

Proactive solutions. The tendency of a fluid to foul process equipment is related to many factors. This is generally caused by suspended solids, dissolved components or separate liquid phases such as emulsions (and the potential combinations thereof). Predicting fouling tendency based on process conditions and stream quality alone is often speculative and inaccurate. A good method for determining fouling tendencies is a validated laboratory simulation of the process and its conditions.

Hot liquid process simulator. One of the best laboratory tests used to simulate process conditions to determine fouling tendencies of a process fluid is the hot liquid process simulator (HLPS). The HLPS is a dynamic laboratory bench apparatus used to simulate fouling in a scaled-down and accelerated way (FIG. 1). By using actual process fluids in the test, the HLPS produces essential information related to process fouling and keeps plants a step ahead of fouling events. This article describes how the HLPS was used to identify the root source of fouling in an aqueous stream, and enabled the facility to devise a more informed and effective mitigation strategy.

The HLPS consists of a reservoir charged with the sample fluid that is pumped through a test section. Electrically heated metal elements or rods (FIG. 2) positioned vertically in the test section form an annulus through which the fluid flows, and the temperature of the element is controlled by a thermocouple located in the interior. Process conditions are simulated by adjusting the flowrate of the fluid and the temperature of the elements or rods. The temperature can be adjusted up to 650°C, and the system is typically pressurized to 600 psi with nitrogen to prevent vaporization of volatile components in the process fluid.

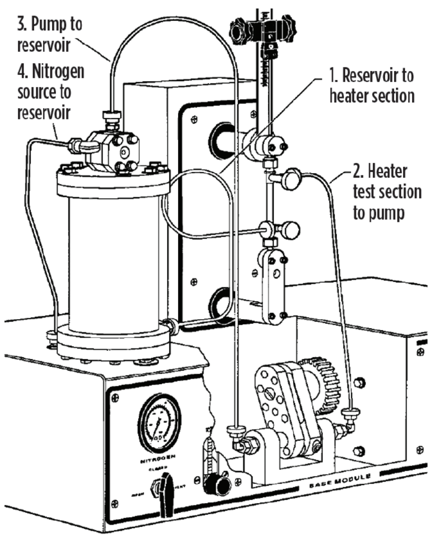

FIG. 1. The hot liquid process simulator (HLPS).

The HLPS measures the degree of fouling by differential temperature (ΔT) or differential pressure (ΔP), depending on the nature of the process fluid. In ΔT mode, the temperature of the fluid at the inlet of the annulus is compared with the outlet temperature. As foulant material deposits on the heated element, heat transfer from the element to the fluid deteriorates, and a subsequent decrease in the outlet temperature is recorded (FIG. 3). In ΔP mode, the fluid is pumped through the annulus into a small, 1.7-micron filter. Any foulant material in the fluid, generated by exposure to the heated element in the annulus, will accumulate in the filter and cause the differential pressure to increase as a function of time.

Fouling tendency analysis can be used to predict fouling in many liquid streams,

FIG. 2. Heated metal rods used in HLPS testing of treated and untreated aqueous samples. Hydrocarbon deposits and increased total deposition were observed on rods used in the testing of non-extracted samples.

both aqueous and hydrocarbon, and the produced foulant material can be subjected to further analysis to proactively determine the best feed contaminant removal method for the process. Determination of fouling tendency using the HLPS is a powerful tool that can help assess the impact of processing feedstocks and intermediates (aqueous or hydrocarbon-based). In relation to filtration and other separation processes, fouling tendency analysis is useful for determining the optimal treatment method to address fouling issues. This has a fundamental impact in determining whether filtration is the most effective mitigation strategy for a given process fouling event. It also can be used to investigate other alternatives, such as liquid contaminant or emulsion removal (often via coalescence) or chemical additive treatments. As such, the HLPS test is an invaluable test for fouling root-cause determination, as well as mitigation strategy determination.

Case study. A natural gas processing plant in North America was experiencing severe problems with fouling at its methanol recovery unit distillation column and prefilters. The feedwater contained between 50 ppm and 70 ppm of suspended solids and approximately 1% of hydrocarbons. Fouling of the tower packing and filter plugging caused excessive maintenance, reduced throughput and decreased efficiency, and impacted the efficiency of other units downstream. The methanol recovery unit was evaluated, including a comprehensive analysis of the feed components and the process, to find the best solution for fouling reduction.

The feed composition was first analyzed to understand the nature of the contaminants and the feed itself. Visual observation of feed samples revealed high free hydrocarbon contamination (1%) and high suspended and settled solids. X-ray diffraction (XRD) and energy-dispersive X-ray spectroscopy (EDS) analyses were performed on suspended solids from the feed and showed a wide range of contaminants (TABLE 1). Large amounts of iron and carbon undetected by XRD analysis were present in the EDS results, indicating an amorphous deposit typical of asphaltene precipitation and hydrocarbon-coated solids. The HLPS test system was used to determine the fouling impact of these solids and hydrocarbon contaminants.

Three samples were tested by HLPS: an unaltered sample, a filtered sample and a filtered sample with free hydrocarbon

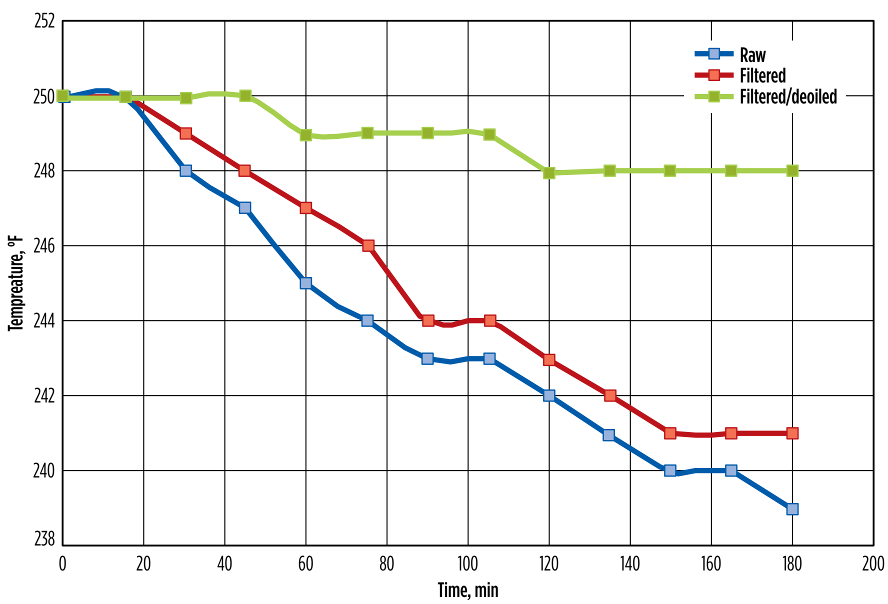

FIG. 3. Outlet temperature data produced from HLPS testing of treated and untreated aqueous samples (inlet temperature maintained at 250°F).

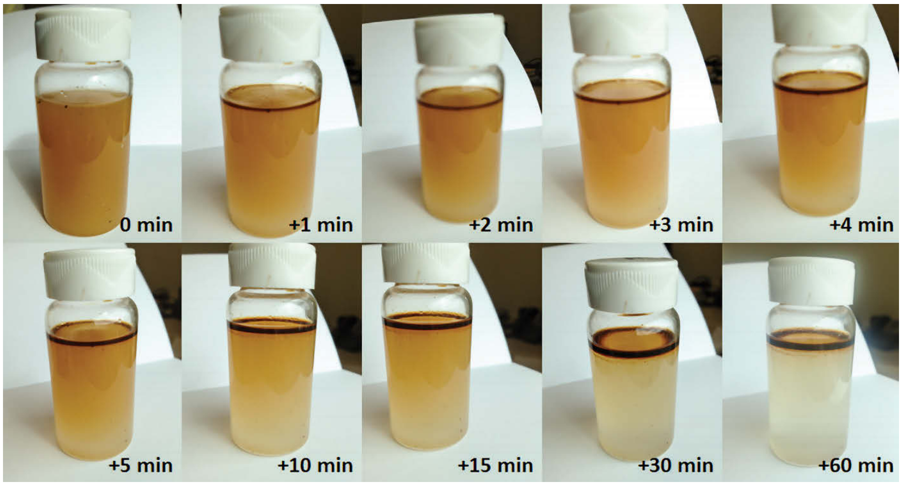

FIG. 4. Time-lapse study of phase separation after homogenization of feed samples. After 30 min, the hydrocarbon and water in solution had almost completely divided into separate phases. After 1 hr, the aqueous phase is clear, indicating the absence of free or emulsified hydrocarbon.

TABLE 1. Elemental analysis of suspended solids in feedwater/methanol, as detected by EDX and XRD

Element	EDX, %	XRD, %
Hydrogen, H	–	0.01
Carbon, C	30.89	2.41
Nitrogen, N	–	–
Oxygen, O	29.35	33.48
Sodium, Na	0.92	3.05
Magnesium, Mg	0.04	0.57
Aluminum, Al	0.2	1.22
Silicon, Si	3	12.59
Phosphorus, P	0.5	1.2
Sulfur, S	1.76	6.85
Chlorine, Cl	1.37	5.23
Potassium, K	0.61	2.34
Calcium, Ca	0.97	3.53
Iron, Fe	22.32	12.68
Copper, Cu	0.29	5.68
Barium, Ba	7.79	9.18

Note: The difference in compositions between the two sets of data are indicative of non-crystalline solids not detected by XRD analysis.

Identifying fouling causes, possible mechanisms and tendencies is critical to eliminate or reduce process fouling. The presence of dissolved components, suspended solids, hydrocarbon or water phases and emulsions should be tested, analyzed and correlated with fouling when possible. These parameters must be carefully monitored to anticipate potential fouling events.

removed. The study conclusively showed that fouling of the test element was greatly reduced after hydrocarbon removal (**FIG. 2**). Deposition of foulant material on the test elements, as well as a marked decrease in differential temperature, was observed in those samples where hydrocarbon was not removed prior to HLPS testing (**FIG. 3**). With the results of this testing, plant engineers in the methanol recovery unit were able to proceed with a better understanding of fouling reduction by focusing on hydrocarbon removal in addition to solids filtration. However, it is important to stress that in this case, if filtration improvement alone had been recommended based on the high particulate matter, the overall impact on fouling would have been marginal. The key solution in this case was to remove suspended solids by adequate filtration in combination with hydrocarbon separation and recovery from the feed stream.

It was established that the source of hydrocarbon contamination in the feed arose from inefficiencies at several upstream three-phase separators. The installation of an oil-water separator at the methanol recovery unit feed inlet was recommended. To understand the separation rate of the hydrocarbon from the bulk feedwater, a time-lapse study was performed (**FIG. 4**). The feedwater sample was shaken to homogenize, and the phases were allowed to separate into organic and aqueous component phases over the course of 1 hr. Separation was complete in 30 min–45 min, indicating that a residence time API device for an oil/water separator would be an efficient system for hydrocarbon removal.

The filtration system in place for the feedwater consisted of two bag filters set in parallel and run in rotation. The filters (**FIG. 5**) were nominally rated for 10-micron (nominal 80%–85% efficiency) particle capture (no efficiency information was available) and were observed to have low efficiency in removing smaller particle sizes. Due to the particle distribution (**FIG. 6**) and hydrocarbon contamination, the filters were also plugging rapidly, causing reduced filter lifetimes and increased filter changeouts. An upgrade to the filtration system was recommended to improve solids retention, accommodate smaller particle sizes and hydrocarbon contaminants, and increase filter lifetimes. The recommended glass microfiber-based filter was pleated to increase the available surface area and to reduce pressure drop across the newly installed elements. The filter vessels in place were reconfigured to accommodate these cartridge-style elements and improve the solids removal efficiency in the feed stream, in addition to increasing filter online life.

Root cause troubleshooting and analytics. A thorough and holistic understanding of process conditions and appropriate root cause analysis are key to resolving fouling and other issues. Specialized analytics and data interpretation are necessary for finding and resolving root cause problems that contribute to fouling episodes. Filtration systems can be analyzed for solids removal efficiency, often revealing the real solids removal efficiency and the impact on downstream fouling. Coalescing systems in both gas and liquid streams also can be effectively and quickly tested to provide valuable insight about actual separation performance and contaminant breakthrough.

Several resources and strategies can be used to determine the best path forward for fouling mitigation, and the best possible solutions can be identified using advanced analytics, expert troubleshooting and innovative, results-oriented solutions. The ability to identify sources and mechanisms of fouling is vital to plant operations, and every fouling issue should be approached differently and proactively, with proper analytical techniques. Only then can suitable separation

FIG. 5. Bag filter and filter vessel in place at the feed to the methanol recovery tower. The 10-µm nominal rated filters were experiencing low solids removal efficiency, rapid plugging and short online life.

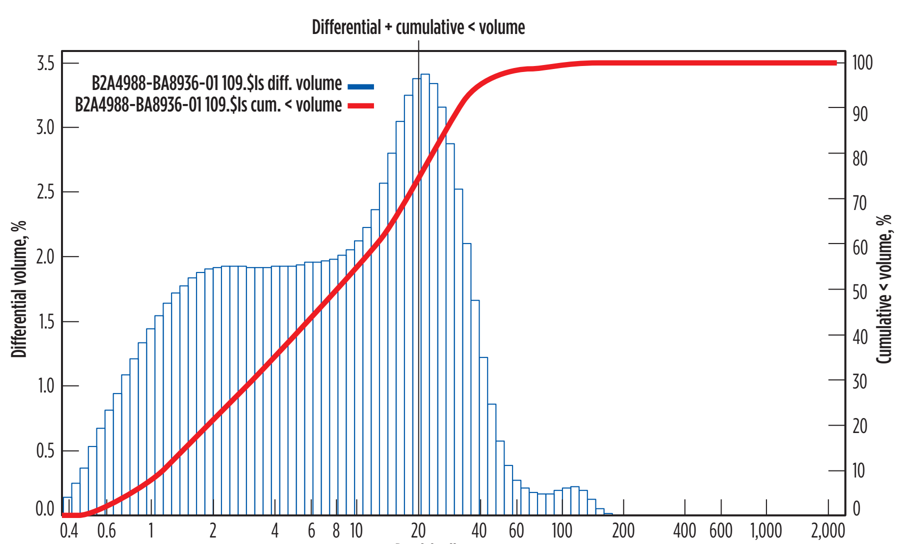

FIG. 6. Particle size distribution of suspended solids in the feed to the methanol recovery tower.

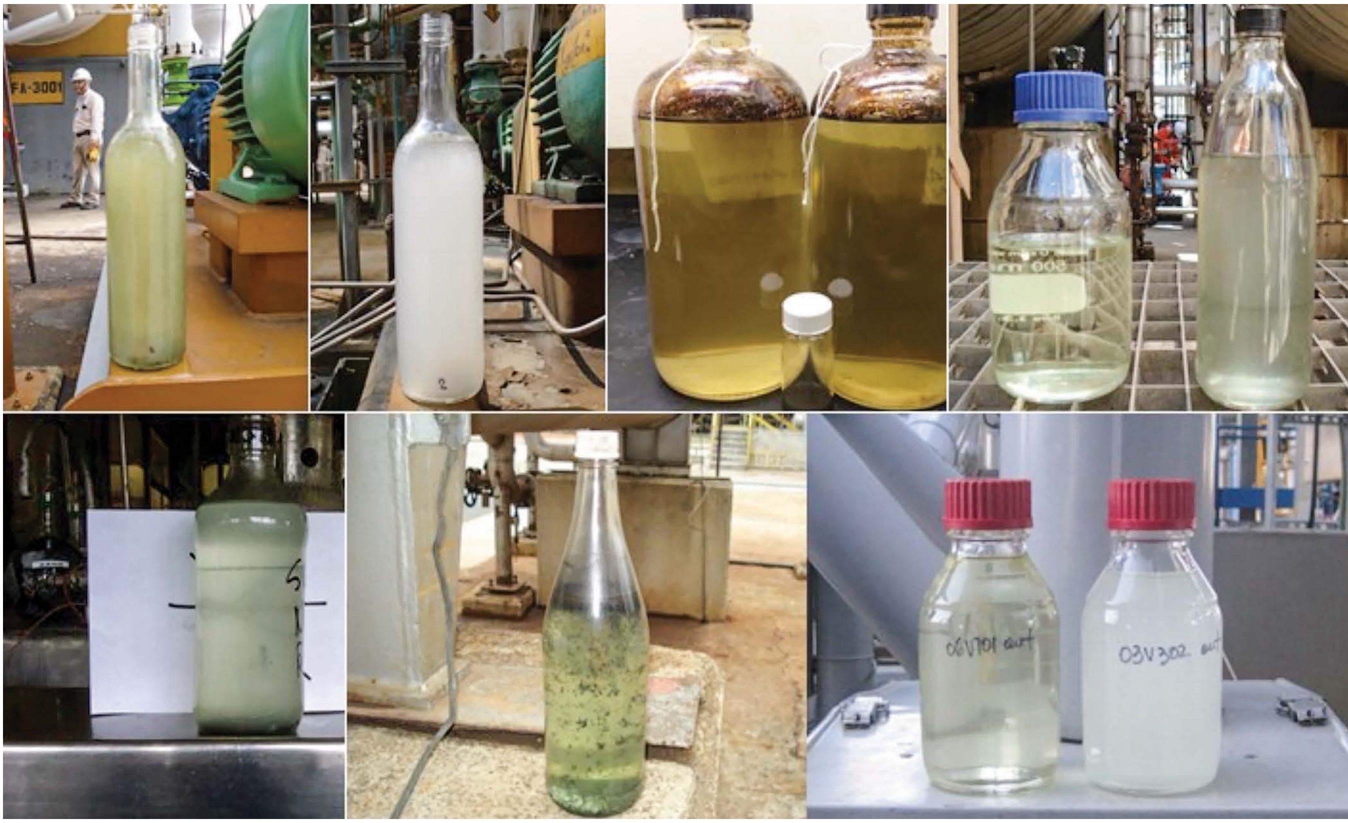

FIG. 7. Photographs taken of sour and produced waters from several different processes.

technologies be conceived, designed and implemented effectively.

When dealing with fouling challenges in aqueous streams, such as the case described previously, it is important to look at the problem with an unbiased perspective and a holistic approach with due consideration to processes upstream. Produced and/or sour water streams vary dramatically in their sources, compositions and contamination profiles; therefore, their fouling tendencies and contamination separation strategies can also vary greatly.

FIG. 7 shows a series of photographs of several process sour waters and produced waters in plants around the world. Upon visual inspection, it can be immediately seen that the variability of these water streams is substantial. Hazy samples are consistent with micro-emulsified hydrocarbons and, in some cases, dispersed suspended solids. Samples with suspended solids presence indicate considerable upstream contamination or corrosion. With respect to separation alternatives, streams with both hydrocarbons and suspended solids pose the most complex scenarios for effective contamination removal. The interaction of both contaminants can, in many cases, generate gel-like materials that can film over filters and coalescers or any other surface. This will rapidly cause plugging, leading to an increase in differential pressure, thereby considerably shortening the working life of any separation system. Similarly, the modes by which fouling occurs in the different process streams vary based on the contaminants present, as well as the process conditions.

Several ways exist to deal with fouling in sour or produced process waters. Identifying fouling causes, possible mechanisms and tendencies is critical to eliminate or reduce process fouling. The presence of dissolved components, suspended solids, hydrocarbon or water phases and emulsions should be tested, analyzed and correlated with fouling when possible. These parameters must be carefully monitored to anticipate potential fouling events. Changes in fouling tendency with changes in process conditions (*T, P,* flowrate, etc.) should be carefully monitored. When fouling events take place, methods like the HLPS and other techniques can be used to understand potential fouling mechanisms. This will enable proper solutions or mitigations for fouling to be impemented. **GP**

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The smart gas plant: An integrated, intelligent gathering and processing super system

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Midstream operators typically own both the gathering networks that transport natural gas and the downstream treating and processing facilities that convert this raw feed into marketable products, such as residue gas and Y-grade NGL.

The optimization of both the gathering system and processing facilities—with their multitude of associated meters, commercial contracts and variable commodity pricing—in an integrated fashion is challenging to carry out in real time. System size, complexity and data requirements can complicate the real-time optimization of these facilities.

However, the overall benefits of this optimized natural gas gathering and processing super system can be significant in terms of lower operating and maintenance expenses, increased reliability and asset utilization, higher-value product recovery rates, and increases in effective system capacity.

The heart of this integrated super system is the smart gas plant, a fully realized, operational digital twin of the plant. When combined with other operational digital twins for the compressors, meters and pipelines, an integrated, intelligent super system is created.

This article describes the use of an operational data infrastructure[a] in configuring a smart gas plant for real-time monitoring and optimization of plant operations, as a first step in creating an integrated super system. The super system enables the optimization of the complete gathering and processing system, comprising many gathering networks and an associated fleet of processing plants, with optionality to gate natural gas to several gas plants based on optimal guidance.

Gas plant operational challenges. The gas plant is the heart of a gathering- and processing-focused midstream operator's asset portfolio because of its role as the treating and processing hub, which receives raw gas from the gathering network, removes contaminants such as H_2S, CO_2 and water in amine and glycol units, and separates NGL and sales gas in a cryogenic unit.

The challenge for gas plant operators is to optimize plant uptime and equipment maintenance to ensure consistent, optimum and high-quality sales gas and NGL production rates, while balancing numerous issues, including:

- Feed gas rate composition/quality variability
- H_2S and CO_2 concentrations exceeding environmental limits
- Running the cryogenic unit in ethane recovery or rejection mode
- Controlling residue gas heating values
- NGL composition ratios, such as C_1/C_2 and CO_2/C_2, as well as fluctuating methane, ethane and propane prices.

The capability to carry out this analysis for gas plants and act in near-real time, vs. an offline weekly or monthly reactive approach, is essential for responding rapidly to operational and price/market fluctuations, as well as optimizing production. Near-real time, financial-based optimization of a single gas plant train can yield \$2,500/d–\$3,000/d (approximately \$1 MM/yr), and up to 1.5 times this amount per gas plant in a gathering and processing super system.

Extracting actionable insights and optimizing gas plant performance is challenging due to the large and diverse amount of operational, meta and financial data from disparate sources: distributed control systems (DCSs), programmable logic controllers (PLCs) and other sensors; financial/pricing databases; commodity pricing and enterprise resource planning (ERP) platforms; computerized maintenance management systems (CMMS); plant process simulation tools; and many others. Examples of such data types include:

- Plant process sensor data, such as temperature, flow, pressure, concentrations, etc. from the DCS
- Raw gas quantity, quality and gathering system information
- Manufacturer equipment performance curves and related engineering data
- Plant asset maintenance records
- Plant process simulation models that are validated and provide optimal operating targets
- Financial information associated with methane, ethane and propane pricing from multiple sources, including a multitude of contracts and commodity pricing.

An operational data infrastructure[a] is a key foundational tool to enable the creation of a smart gas plant. An operationally intelligent operational digital twin of the physical gas plant can turn these disparate data sources into actionable operational intelligence and decision support. This digital infrastructure empowers engineers, operators, maintenance personnel and subject matter experts (SMEs) to configure, evolve and manage their gas plant decision support application directly, using the data infrastructure[a] with "no-code" digital twins.[b] This is in contrast to the more traditional approach of developing or purchasing a customized digital solution for gas plant operations with significant IT involvement, associated customization and challenging sustainment effort.

Real-time decision support. The smart gas plant is based on an integrated, hierarchical set of configurable dashboards that enables self-serve, contextualized access to operational intelligence, using a modern, web-enabled visualization platform.

As a best practice, the smart dashboard should have a rolled-up summary of all gas plant information, including integration with geospatial, safety and environmental information, with the ability to drill down through the portfolio of smart displays. The smart displays should leverage exception-based, conditional formatting to communicate equipment status efficiently and effectively.

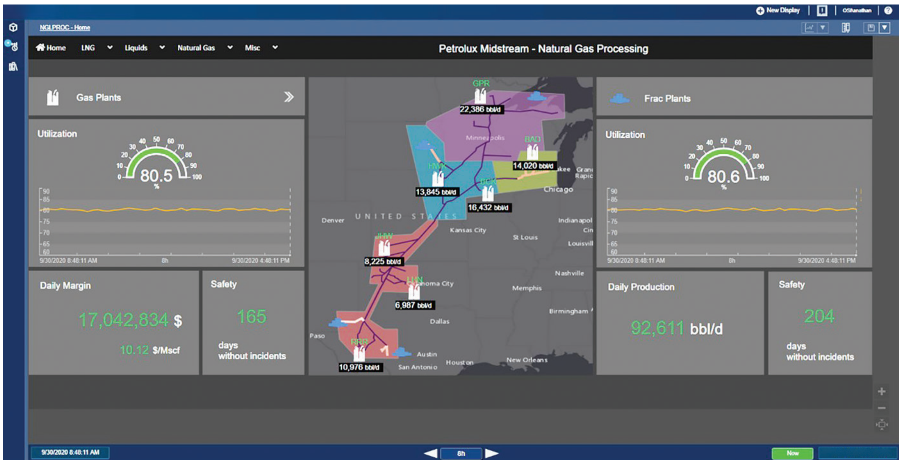

FIG. 1. Example of a smart, configurable gas plant summary dashboard.

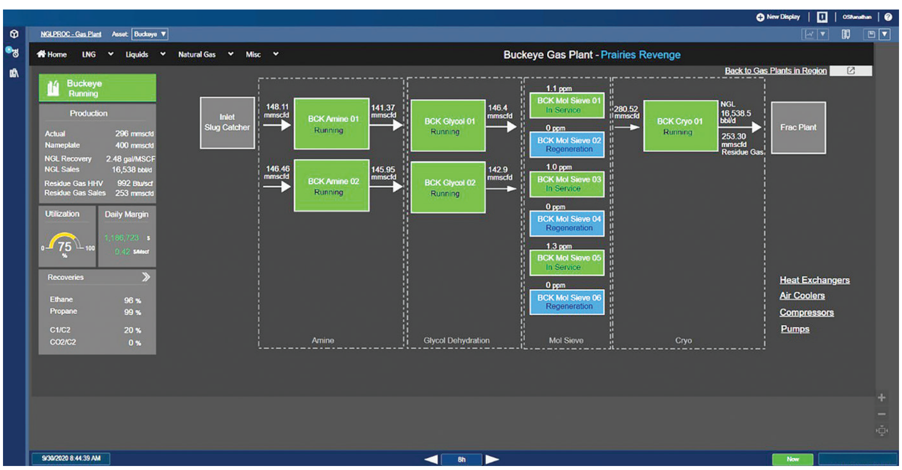

FIG. 2. Plant block diagram showing different gas plant units and operating KPIs.

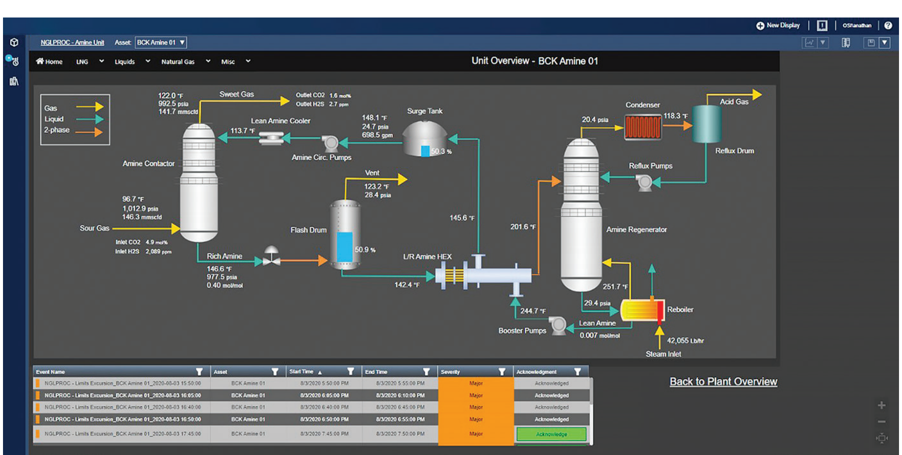

FIG. 3. Process display of an amine unit with environmental excursion events.

FIG. 1 is an example of a smart display developed for a midstream company with several gas plants in its asset portfolio. This smart display was configured by dragging and dropping desired plant attributes from a gas plant asset hierarchy onto a smart display canvas. As no programming or coding is required, end users can customize their own smart displays or rely on standard, enterprise-level smart displays. This display also has a conditionally formatted geospatial map layered with real-time information, such as plant production rates. By selecting a region on the map, further drill-down details and intelligence can be accessed.

Additionally, the summary dashboard has rollup KPIs, such as overall plant utilization and production, which are configured and managed by the plant SMEs. The web-based dashboard also showcases financial KPIs, such as daily total margin and margin per million standard cubic feet (MMsft^3) of feed gas. Other information, such as safety days, can be linked from associated data sources.

A user can drill down from this summary display to view a block diagram and operating KPIs for each individual gas plant in a specific region, such as NGL and residue gas production rates, ethane and propane recoveries, as well as C_1/C_2 and CO_2/C_2 component ratios (**FIG. 2**). By selecting a block, a process flow diagram (PFD) of the unit with real-time process values can be viewed.

Since the display shown in **FIG. 3** is referencing an amine unit that uses an underlying "no-code" digital twin template,[b] the user can easily configure this dashboard for one amine unit and then reuse it for all other amine units in the asset portfolio without modification. This capability significantly reduces smart display creation and management workloads.

This display also shows environmental excursion events, specifically when the outlet H_2S concentration from the amine contactor exceeds 4 ppm, which is an emissions limit. These environmental excursion periods can be automatically

created by defining a rule-based start and end event analytics. Another powerful capability is "backcasting" these event analytics (or any expression) on high-fidelity historical data to enable insight into when the defined event occurred in the past. These events can automatically trigger notifications to the operators, SMEs and other relevant parties or workflows to external systems, such as work order creation.

For maintenance personnel, equipment-centric views into all heat exchangers, air coolers, compressors and pumps in a gas plant can be developed. When an asset class, such as a heat exchanger, is selected from the list in **FIG. 2,** a display listing all relevant operating KPIs for each exchanger can be configured with exception-based reporting rules to visually indicate which exchangers need attention (**FIG. 4**).

The gas plant digital twin becomes increasingly "smart" when integrated with a robust plant process simulation tool that has validated models of all necessary plant units. Model intelligence is further enhanced by bi-directionally integrating real-time plant DCS/sensor data from a historian as inputs to the simulation model and historizing the simulation results to perform real-time comparisons between simulation and operating parameters or validating the model. The display (**FIG. 5**) illustrates ethane and propane recovery comparisons from both real-time and simulated data. The live link between the operating and engineering models, coupled with financial data (e.g., ethane and propane spot pricing), enables real-time, recovery-based financial performance optimization to be implemented in the smart gas plant.

Portfolio and fleet-wide gas plant business intelligence. Once this recovery-based financial performance optimization methodology is developed for a single gas plant, it can then be applied throughout the plant portfolio in a midstream company. Fleet-wide business intelligence (BI) dashboards can be developed by streaming this data in real time to tools such as Microsoft Power BI, Tableau or Spotfire.

Users can quickly view these recovery values vs. model-validated targets for all plants in a central display, taking advantages of features such as slicing and dicing in these BI platforms to understand portfolio performance and take appropriate actions.

Creation of a gathering and processing super system. Once the portfolio of gas plants has near-real-time optimization, the same strategy and methodology can be extended to pipeline gathering assets, including associated systems, such as compressor stations and meters, to build a smart pipeline system.

The smart digital replica of the gas plants and the digital replicas of the associated gathering systems can be combined to form an integrated, intelligent gas gathering and processing super system (**FIG. 6**). By leveraging the super system optionality, such as gating a gathering system to the most optimal gas plant, the gathering and processing operator can gain as much as 1.5 times of financial performance across the super system vs. optimizing a single gas plant.

Several gathering and processing operators have reported an increase in super system effective capacity by more than 3%, enabling the idling of low-efficiency gas plants or the ability to secure additional gathering and processing volumes.

This integrated super system can now be utilized to holistically monitor and optimize the entirety of a midstream operator's asset portfolio. The super system helps maximize production and financial returns, minimize costs and ensure safe and reliable operations, leading to optimum gas volumes and routing from the gathering network to high-efficiency gas plants based on spot prices. In addition, based on this super system, management decisions can be made to either sell or idle under-performing or low-efficiency plants that are not needed based on gas demand and present contract pricing.[2]

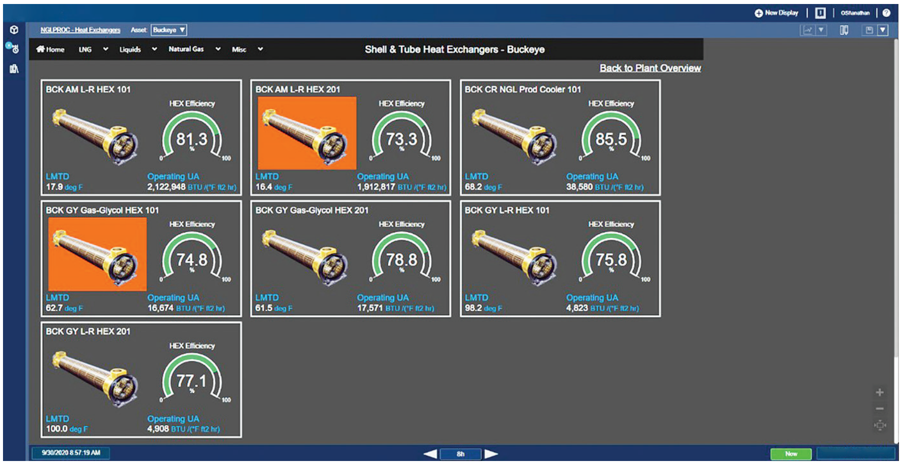

FIG. 4. Exception-based equipment reporting display for all heat exchangers in a gas plant.

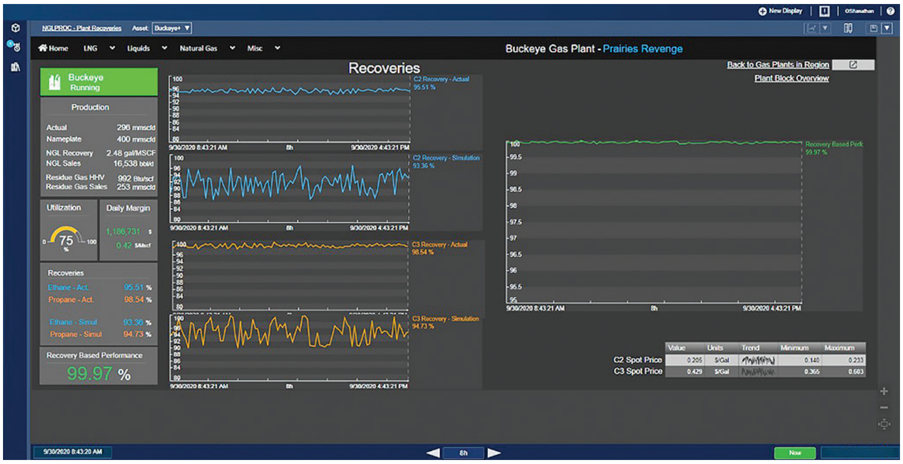

FIG. 5. Comparison of C_2 and C_3 recoveries from operating and simulated data, with recovery-based financial performance optimization.

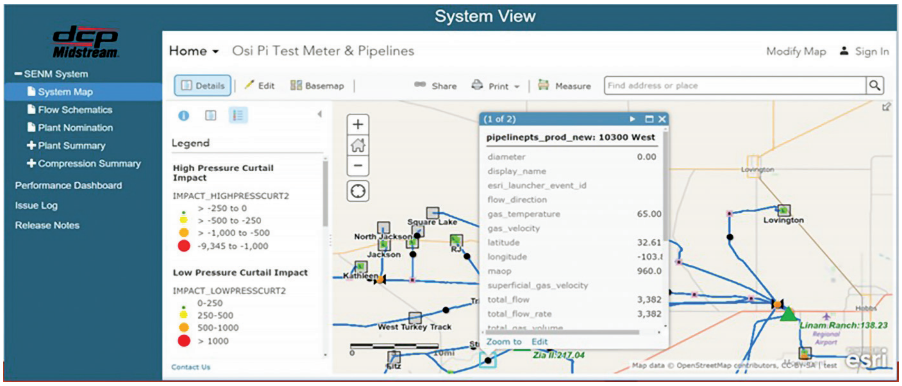

FIG. 6. An integrated, intelligent gas gathering and processing super system, combining smart gas plants with digital pipelines.[1]

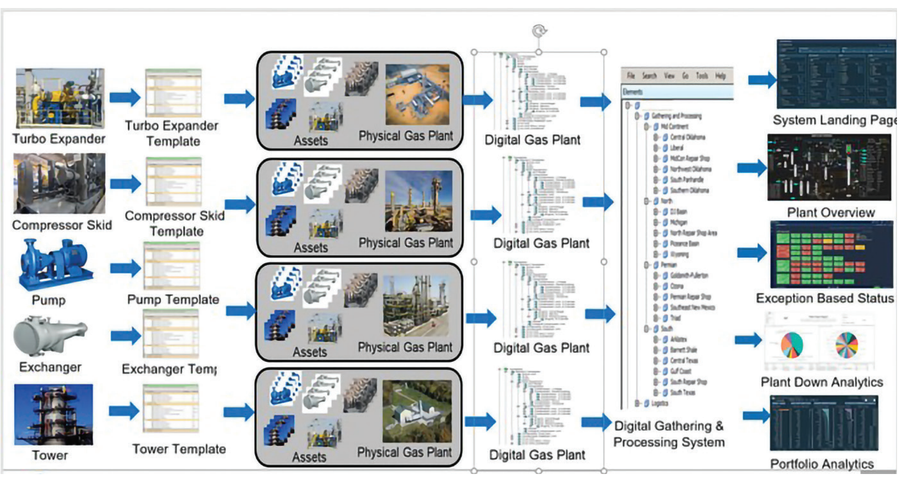

FIG. 7. A smart gas plant configuration from digital twin asset template building blocks.

Real-time operational data infrastructure. The real-time operational infrastructure[a] is an agnostic, open, scalable and reliable technology specifically designed for critical operations. It enables several key functionalities:

- Secure integration of time-series operational data from DCS, supervisory control and data acquisition (SCADA) and Industrial Internet of Things (IIoT) systems
- Abstraction of diverse tag and asset names into a standard company lexicon
- Integration of metadata, including engineering data and the maintenance management system
- Normalization of units of measure, time zones and descriptions
- Configuration of traditional operational applications, such as energy management, environmental compliance and KPI-driven dashboards
- Use of a "layers of analytics" framework and strategy providing the analytics foundation via descriptive, diagnostic and simple predictive analytics.

No-code digital twins. A digital twin is a replica of a physical asset, such as a heat exchanger, a pump or a compressor comprising attributes, calculations, KPIs, empirical correlations and models of varying complexity. Contrary to the present hype, digital twins have been around since the 1960s. However, today's operationally focused digital twins are dramatically more robust and sophisticated in their ease of use, approach and capability to develop, evolve and leverage in a smart gas plant.

Most digital twins require information technology (IT), data scientists, machine learning, model integration and coding. They also have a limited ability to deal with data volume, velocity, variability and anomalies. They are difficult to scale and struggle to address the anomalies of physical assets that have variability in vintage, make, model and level of instrumentation. Furthermore, real-time operational data and asset metadata (i.e., static information like equipment model and location) typically reside as tags in control systems, as well as in other databases and platforms, with accessibility issues and lack of naming standards limiting access to critical data that could potentially be leveraged to gain insight.

However, one operations-focused digital twin technology[b] has access to this required data with the ability for the SMEs to configure replicas of their gas plant components, such as columns, heat exchangers, pumps, compressors and air coolers in an agile, evolutionary way. These no-code digital twins rely on digital asset templates and can be combined like LEGO blocks to form a comprehensive digital representation of physical gas plant and gathering and processing system, using drag-and-drop capabilities (**FIG. 7**).

The digital operational infrastructure can enable asset anomaly detection by empowering the SME to create or modify anomaly expressions and then test the expressions by backcasting—i.e., running the expression back into the operational history. Once satisfied with the expression, the SME can then forward-cast this modified expression or event detection algorithm to other assets that utilize the same digital twin template. This powerful capability enables continuous improvement of calculations, expressions and event analytics over time, as well as comparison of similar expression results, KPIs or events as part of the diagnostic process.

To be able to address the variances in equipment type, make and vintage, the digital twin templates must contain subtemplates or derived templates to capture these deviations from the base template. In the digital twin templates, the attributes are placeholders for the actual, asset-specific values that are mapped once when the template is applied to an actual asset.

A real-world data infrastructure[a] with no-code digital twin technology[b] now operates across DCP Midstream, one of the largest midstream operators in North America. DCP Midstream has numerous gas plants, fractionation units and other midstream assets, including thousands of associated heat exchangers, pumps,

and compressors. DCP Midstream's engineers have configured more than 400 no-code digital twin templates in an evolutionary, agile way to form an operational digital twin of their entire enterprise, with more than 11,000 digital twin instances.

"Layers of analytics" strategy for gas plants. Terms such as advanced analytics, machine learning, big data and artificial intelligence (AI) appear pervasively in marketing literature today, but they can lead to confusion, failed projects and significant lost-opportunity costs.

The most successful gas plant operators achieve value from analytics by first defining an analytics framework and the types of analytics required, and then selecting fit-for-purpose technologies. They use a layers of analytics strategy, which considers incremental cost vs. incremental value as they move to more complex analytical methods. The costs include not only the technology, but also the costs associated with lost time to value, scalability, configuration, sustainment and risk of attainment.

The foundation of this layers of analytics approach (**FIG. 8**) relies on the use of an operational data infrastructure to enable SMEs—not IT—to configure real-time descriptive, diagnostic and simple predictive analytics using formulas, empirical correlations and rule-based expressions. These lower-level analytics form the foundation for more advanced predictive, prescriptive and adaptive analytics that use machine learning and other methods and require collaborative support from data science teams.

These foundational analytical layers generally provide more than 80% of the value for about 20% of the cost vs. more advanced analytical layers that use only technologies such as machine learning. Once higher layers of analytics are utilized, it is imperative to feed back the results of these advanced layers to the lower-level layers as forecasts or targets to operationalize the advanced analytical output. This is key to the development of the smart gas plant, as results from the integration with process simulation optimization models and financial data for real-time gas plant financial optimization are fed back to the operational data infrastructure.

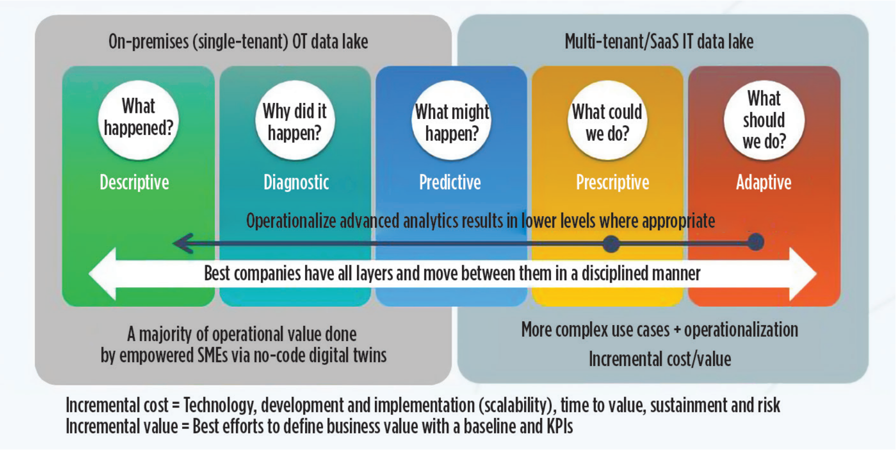

FIG. 8. A "layers of analytics" strategy—disciplined evolution of analytical layers to deliver value.

Takeaway. Natural gas gathering and processing operators face numerous operational and market challenges that inhibit their ability to achieve optimal operating and financial performance. Leading gathering and processing companies are responding to these challenges by aggressively adopting digital technologies that enable agility, flexibility, operational excellence and proactive decision support to optimize performance through the development of smart gas plants and gathering and processing super systems.

The overall benefits of this optimized natural gas gathering and processing super system can be significant in terms of lower operating and maintenance expenses, increased reliability and asset utilization, higher-value product recovery rates resulting in \$1 MM/yr per gas plant, and increases in effective gathering and processing system capacity by as much as 3%.

Adopting an operational data infrastructure with no-code operational digital twins based on a layer of analytics strategy, as well as building smart dashboards, are the keys to a successful digital transformation. The enablement of SMEs to develop, configure and evolve these no-code digital twins with minimal IT support is the secret to the smart gas plant of the 21st century. **GP**

NOTES

[a] The PI System functions as a real-time operational data infrastructure for critical operations and enables SMEs to configure no-code digital twins to create self-serve access to contextualized operational intelligence and support a layer of analytics strategy.

[b] No-code digital twins refer to the PI System's Asset Framework (AF) that includes an integration, abstraction and contextualization layer via data references to other data sources; a portfolio of 110 analytical functions optimized for time-series data that leverage a wizard capability for ease of use; event framing that enables configurable event start and end times with event analytics; and a configurable notification engine to trigger alerts via SMS, email or work order in a maintenance management system.

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Process technologies for LNG production

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LNG is purified natural gas converted into liquid form. In this physical state, NGL takes up 1/600th the volume of gas in its natural form, making it economical to be stored in large-volume containers and transported over long distances via tanker.

The English scientist Michael Faraday first developed a way to liquefy methane in 1820. However, LNG first made its way to commercial application in 1959 when the first LNG tanker, the *Methane Pioneer,* sailed from Lake Charles, Louisiana, U.S. to Canvey Island, UK, where the government wanted to convert coal to natural gas following the Great Smog of 1952.

LNG international trade followed with LNG export from Algeria to the UK in 1964. Soon after, France imported LNG from Algeria, and Spain and Italy imported LNG from Libya. Today, the LNG industry has become the catalyst for the transformation of the global gas sector.

The LNG industry consists of three main processes: liquefaction and storage, ocean transportation via tankers, and storage and regasification. As an alternative to land-based projects, the liquefaction, storage and regasification steps can also take place on vessels, which include:

- FSRU: Floating storage and regasification units
- FLNG: Floating LNG vessels
- FPSO: Floating production, storage and offloading systems
- FPS: Floating production systems
- FSO: Floating storage and offloading systems
- FSU: Floating storage units.

In addition to the traditional uses of natural gas, and for its reduced environmental impact relative to coal and other fossil fuels, LNG has become popular as a clean energy vector in the maritime and transport sectors. This trend has also stirred interest in small-scale LNG plants.

Process technologies for LNG. Once natural gas has been pretreated to reduce the impurities to trace levels—i.e., water to 0.1 ppm, CO_2 to 50 ppm and Hg to less than 10 ng/Nm^3—LNG is liquefied and subcooled by cooling the gas to −162°C (at 1 bar abs).

Natural gas liquefaction requires a significant amount of refrigeration. Since the adopted refrigeration cycles differentiate the commercial liquefaction processes, the most widely used refrigeration systems in the LNG industry are outlined in the subsequent sections, followed by the commonly used LNG production technologies.

Refrigeration cycles. The refrigerant fluid can be a single-component fluid (N_2, for instance) or a mixture of light hydrocarbons, generally termed as mixed refrigerant (MR).

In the latter case, the MR speciation can be varied to accommodate changes in the operating conditions. For example, in locations characterized by strong seasonal variations in ambient temperature, the MR composition is varied to accommodate these changes.

The selection of the refrigeration cycle is driven by the LNG production pattern. When the LNG is to be produced for peakshaving purposes, for example, the liquefaction plant does not operate on a continuous basis and the capacity is small. In these cases, the focus is on CAPEX rather than high efficiency, and the refrigeration cycle may be based on an inverted Brayton refrigeration (BR) cycle. In the BR cycle, refrigeration is supplied by expanding a single-component fluid (N_2) without fluid phase change. For medium to large production plants where high efficiency is important, a compression refrigeration cycle (CRC) with refrigerant phase change is used.

Inverted Brayton cycle. In the basic BR cycle, the cooling duty is provided by expanding nitrogen through a Joule–Thomson valve, or through an expander, without causing a change in the fluid state. The pressure of N_2 is raised from point (1) to point (2) and cooled at constant pressure to point (3) (**FIG. 1A**). In the following isentropic expansion to the pressure $P_4 < P_3$, the temperature ideally drops to T_4, as per the formula shown in Eq. 1, providing the cooling stream against which natural gas can be cooled and liquefied:

$$T_4 = T_3 \times (P_4 \div P_3)^{\wedge[(k-1) \div k]} < T_3 \quad (1)$$

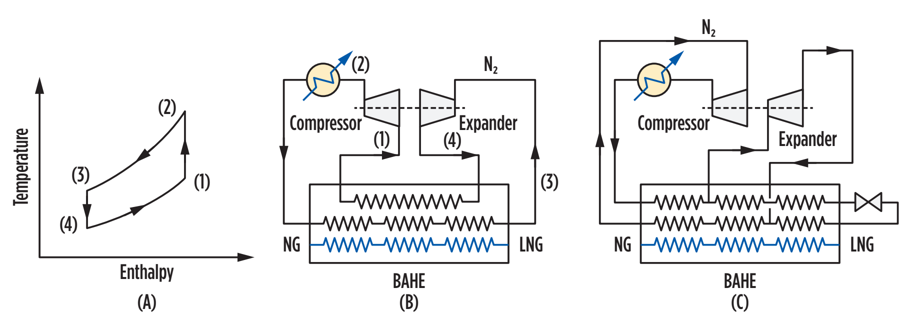

FIG. 1. N_2 expansion refrigeration cycle.

Simplicity of design and ease of implementation are the main advantages offered by the BR cycle. However, since only sensible heat is transferred, the BR cycle may be economically advantageous only for micro- and small-scale LNG production, as increasing the cooling duty would result in an increase of N_2 flowrate and a disadvantageous increase in plant dimensions.

N_2 is not flammable, nontoxic, easy to procure and does not need storage facilities. For these characteristics, the BR cycle is often considered for offshore application where safety is a major issue. Moreover, it is not affected by wave-induced motion.

Compression refrigeration cycle. In the CRC, heat is extracted from a process stream by evaporating, at low pressure, the refrigerant fluid in a kettle-type heat exchanger and rejecting heat by condensing the refrigerant vapor at relatively high temperature.

The rejection is accomplished by transferring the extracted heat to an external utility or to a heat sink within the process, or to another refrigeration system (cascade refrigeration). The simplest refrigeration closed cycle entails a sequence of evaporation (heat extraction at low pressure), compression, condensation (heat rejection at high pressure) and expansion. "Closed cycle" means that the working fluid of the refrigeration system is permanently contained within the mechanical system.

In the context of the LNG industry, the thermodynamic efficiency of the basic closed cycle can be improved by increasing the number of refrigeration stages or by using more than a single working fluid (refrigerant) in a cascade arrangement.

FIG. 2 shows a dual-compression, dual-expansion refrigeration system. The refrigerant vapor stream (5) at high pressure is cooled and expanded in a throttling valve. The resulting two-phase flow is separated in the economizer. The vapor is recycled back to the second stage of the compressor after having been mixed with the outlet stream from the compressor intercooler. The pressure of the liquid phase withdrawn from the economizer is reduced by means of a second throttling valve and sent to the evaporator, where it provides the refrigeration duty by evaporating at low pressure.

The thermodynamic transformation taking place in this refrigeration cycle is illustrated in the right side of **FIG. 2.** The power required to transfer heat from the evaporator to the condenser is given by the enthalpy (H) difference between points (5) and (2). If the pressure were raised with only one compression stage, the final state of the gas would be in the position (5*). Since $\Delta H_{(5\text{-}2)}$ is less than $\Delta H_{(5^*\text{-}2)}$, the power requirement of the two-stage compression is less than the power required by a single-stage compression system.

It should be noted that if the throttling valves are replaced with expanders, the efficiency of the refrigeration is further increased because the expansion across a process expander provides additional cooling and power recovery. In most LNG facilities, the precooling of natural gas is accomplished with a tri-stage propane refrigeration cycle.

In the cascade arrangement, two or more refrigerant fluids (generally propane and ethane) are used in two distinct refrigeration cycles. The low-temperature cycle provides the cooling in the evaporator and rejects heat to the other cycle by means of the evaporator/condenser heat exchanger. This latter is common to both cycles. **FIG. 3** illustrates the process setup for a cascade refrigeration cycle. The cascade refrigeration concept was used in early LNG plants.

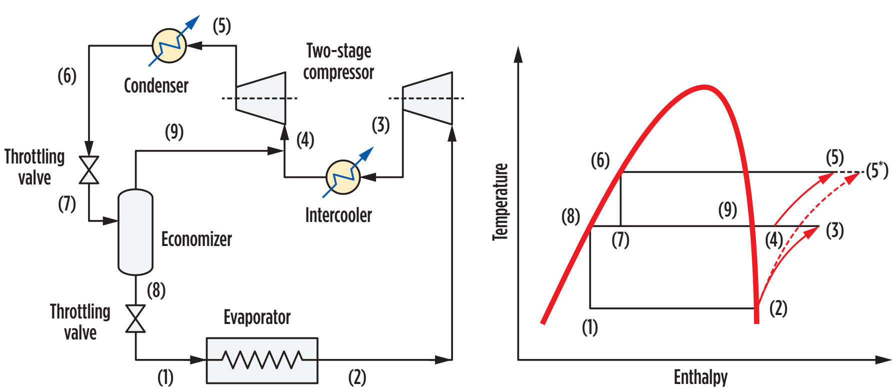

FIG. 2. The dual-compression, dual-expansion refrigeration cycle.

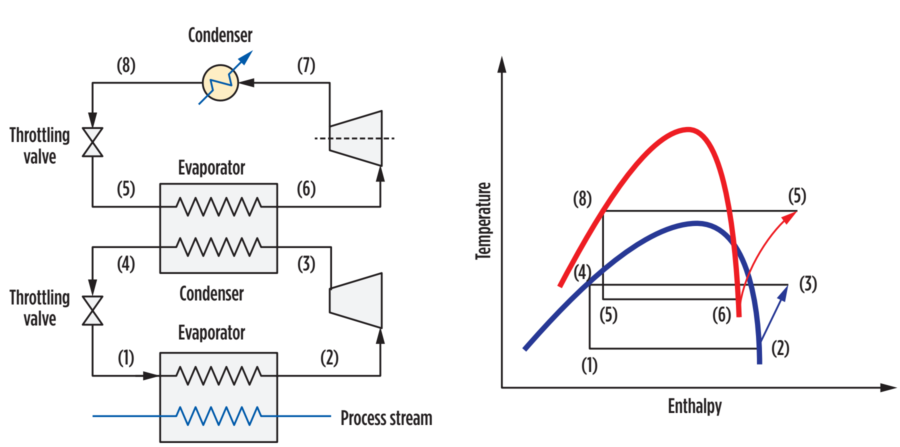

FIG. 3. Cascade refrigeration cycle.

Mixed refrigerant. A single refrigerant fluid must be compressed and expanded to pressures low enough to reach a temperature colder than the process stream. The lower the gas liquefaction temperature, the larger its duty, and generally the more complex the refrigeration system becomes.

Since natural gas is a mixture of components, its condensation curve—the plot of temperature against specific enthalpy (J/kg) or cumulative heat rate—is a monotonic function that decreases over the entire enthalpy domain. An inherent loss of thermodynamic efficiency occurs when attempting to match the discrete single-refrigerant temperature

levels with the condensation curve of process streams.

On the contrary, the boiling curve of a designed mixture of refrigeration fluid can better approach the natural gas cooling curve. In doing so, less external work is required for the liquefaction. MR used for liquefying natural gas generally contains methane (40%), ethane (48%), propane (9%) and nitrogen (3%). It should be emphasized that the actual MR speciation used in a specific plant depends on the natural gas composition and other project constrains, including environmental conditions.

Production plants. The selection of a specific LNG production plant is driven by the feed composition, plant capacity, location, ambient conditions, safety and energy cost. As a short reference, **TABLE 1** provides a list of the main commercial processes segmented according to plant capacity.

Although comparatively less efficient, the N_2 recycle process and its modification account for a large share of production plants in operation today. The simplest system comprises a brazed aluminum plate-fin heat exchanger, a compressor and an expander, as shown in **FIG. 1B.** The circulating N_2 is compressed with a reciprocating, multistage compressor (for micro- and small-scale plants). The warm, compressed gas is cooled to 150K–175K by means of an external utility and auto-refrigeration (i.e., by heat transfer to the cold, low-pressure N_2 stream) and expanded in a Joule–Thomson throttling valve or through a gas expander.

The thermodynamic efficiency of this scheme is very low; the specific power required to liquefy natural gas can be greater than 1.5 kW/kg of produced LNG. The efficiency of this cycle can be improved by allowing the circulating gas to condense so that the latent heat of N_2 can provide part of the refrigeration duty. In this case, the basic N_2 recycle evolves into the process diagram shown in **FIG. 1C.**

Other modifications have been introduced to the basic scheme to improve the overall efficiency of the N_2 refrigeration system. One modification consists of expanding N_2 in three expanders, with each serving the cooling duty of an individual step (precooling, liquefaction and subcooling) of natural gas liquefaction, thereby achieving a split-pressure arrangement.

The selection of a specific LNG production plant is driven by the feed composition, plant capacity, location, ambient conditions, safety and energy cost … Although comparatively less efficient, the N_2 recycle process and its modification account for a large share of production plants in operation today.

Moreover, the multiple expansion allows for an increase in LNG capacity from 0.5 metric MMtpy to 1 metric MMtpy.

In a recent development, the efficiency is improved by combining an N_2 cycle with a CH_4 cycle. The former cycle is for supplying precooling and liquefaction duty, while the latter is for subcooling the produced LNG.

Single mixed refrigerant (SMR). Further improvement of efficiency is attainable by replacing N_2 with an MR that has an adjustable composition to "simulate" the cooling of natural gas from ambient to cryogenic temperature. The SMR combines the simplicity of the plant configuration with operational flexibility while enhancing the overall plant efficiency by 10%–15% relative to the N_2 recycle plants.

In the baseload LNG industry, the most commonly used process configuration is a combination of propane precooled and mixed refrigeration (C3MR) processes. Generally, the propane cycle includes a three-stage refrigeration system where propane is boiled at three distinct temperature levels and the boiling curve forms three distinct steps.

Large production plants are arranged in multiple trains with parallel compressors and relevant drivers. The size of each train is increased to the maximum possible to pursue economies of scale[a] so that the unit cost—i.e., the CAPEX/t of produced LNG—is as low as possible.

Since a large flowrate of gas must be cooled from nearly ambient temperature to yield LNG at –162°C, the high heat transfer required entails a large heat transfer area. The heart of a baseload plant is the main heat exchanger (e.g., a spiral-wound heat exchanger, or SWHE). The SWHE consists of pressure vessels containing a number of tubing bundles fabricated with a large number of long, aluminum tubes helically wound around a mandrel or a central core. Numerous tube layers are formed in the radial direction. Each layer is separated from adjacent layers by spacers.

The SWHE comprises a warm exchange zone and a cold exchange zone. Together, the tubes clustered in the warm/cold zone constitute a single, coil-wound bundle. In the multi-tubes shown at the left of the warm zone in **FIG. 4,** the feed gas is cooled and partially condensed against a vaporizing refrigerant on the shell side of the bundle. The resulting two-phase flow is directed in the bundles of the cold zone, where it is further cooled and extracted as LNG.

The refrigerant in the shell side is a mixture of light hydrocarbons. After being cooled and partially condensed in the MR refrigeration loop, the two-phase flow is separated in a knockout drum. The liquid from the knockout drum is subcooled in the tubes circuit, shown at the right of the warm bundle, and then throttled and mixed with the refrigerant flowing downward from the cold area. The MR flows downward over the outside of the spool bundle. By vaporizing and warming while flowing downward, the MR provides the refrigeration for cooling the feed gas and subcooling the liquid phase extracted from the knockout drum.

TABLE 1. Commercial liquefaction plant capacity selection

Scale	Capacity, metric MMtpy	Process technology
Micro	0.03–0.1	N_2 expander
Small	0.1–0.5	N_2 expander, SMR
Medium	0.5–2.5	SMR, DMR, C3MR, AP-LNG
Baseload	> 2.5	C3MR, DMR, AP-X

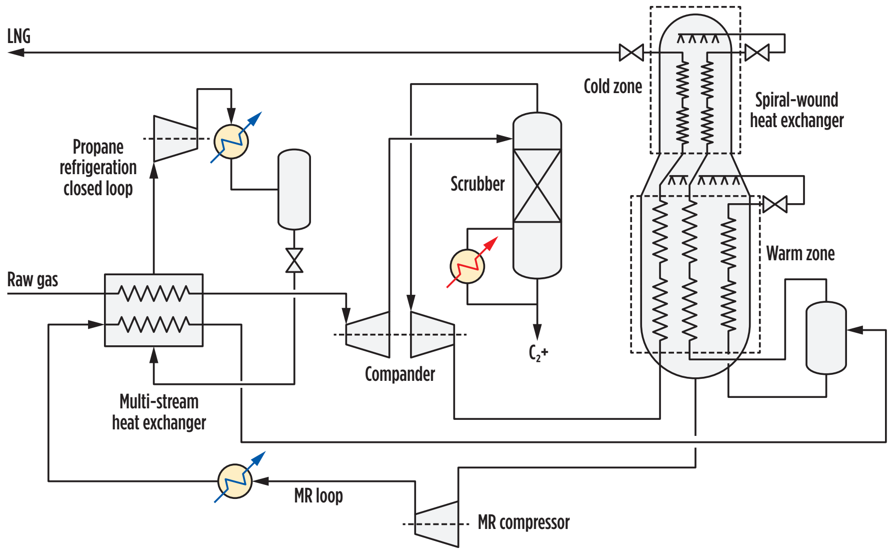

FIG. 4. Propane-precooled SMR liquefaction technology.

The refrigerant vapor from the knockout drum is cooled in the warm zone and passes through the tube circuit in the cold zone, wherein it is liquefied and possibly subcooled. After pressure reduction, it flows downward on the outer side of the spool bundle and evaporates, thereby providing the refrigeration duty to both the feed stream and the refrigerant vapor coming from the knockout drum. The refrigerant flowing downward in the SWHE becomes totally vaporized upon reaching the bottom.

The exchange configuration previously described is known as "top cold." The opposite arrangement is "bottom cold." In the latter configuration, LNG is withdrawn from the bottom rather than from the top.

Note: The vaporization of the MR fluid gradually flowing downward increases, and the heat transfer mechanism changes from two-phase boiling heat transfer at the top of the warm zone to single-phase vapor heat transfer at the bottom. However, the geometric data (e.g., coils diameter, tubes outside diameter, radial tubes spacing, tubes pitch and winding angle) are often kept constant throughout the bundle, meaning that the thermal design of these systems is the result of a tradeoff among the various heat transfer mechanisms.

Aluminum is the material of construction used for the SWHE and BAHE; therefore, a mercury removal unit[b] must be installed in the conditioning section of the processing facilities.

In a more recent enhancement, the C3MR has been integrated with an N_2 recycle refrigeration cycle in the rear end of the process. In doing so, the LNG subcooling duty is shifted from the cold zone of the SWHE to the N_2 recycle cycle, and the capacity of a single LNG train can be as much as 8 metric MMtpy–10 metric MMtpy, if the dimensions are left unchanged. This plant configuration licenses AP-X process technology.

In arctic regions, where the temperature can vary from –40°C to 30°C, the propane cycle becomes a bottleneck in the process because it is not possible to fully utilize the power from the compressor over the wide temperature range. In replacing the propane refrigeration cycle with an MR, the maximum utilization of power available from the compressor drivers can be attained while maintaining efficient refrigerant compressor operation over the wide temperature range. In these cases, the MR is constituted by a blend of ethane and propane. Increasing the proportion of propane creates a heavier mix suitable for summer operation, while increasing ethane yields a lighter mix for winter usage.

Dual mixed refrigerant (DMR). The process where the precooling duty is supplied by an MR heavier than that used for liquefaction and subcooling is known as dual MR (DMR). The DMR process provides the highest thermal efficiency in severe environmental conditions, but also the greatest equipment count, complexity and multiple refrigerant handling.

The cascade process is an alternative technology. In this process, natural gas precooling is carried out in an evaporator/condenser that is common to the high- and low-temperature refrigeration cycles. Since each refrigerant circuit is controlled separately, this technology does not need to adapt the refrigerant composition to natural gas. The most well-known commercial cascade process is ConocoPhillips' Optimized Cascade LNG process. It cascades three pure refrigerants: propane, ethylene and methane.

It should be noted that plant components in cryogenic service are installed inside cold boxes. These boxes are created of a structural framework closed with steel plates, generally painted white, and filled with insulating material like perlite to avoid heat exchange with the surrounding environment.

Finally, the modularization concept is the emerging approach to economies of scale for baseload plants. Modularization entails multiple parallel, standardized, independent, small-scale LNG plants. In this way, new, identical production lines (modules) can be added as the market expands. This enables cost savings and capital budgeting over a longer span of time. **GP**

NOTES

[a] By increasing the size of the plant, the CAPEX increases less than proportionally with the plant capacity (Q), according to the generally used estimate of 0.67. That is, CAPEX1 = CAPEX0 × (Q1/Q0) × 0.67, where CAPEX0 is the investment cost of a plant of capacity Q0 < Q1.

[b] This process was discussed in the Back to Basics article, "Natural gas phase separation and mercury removal," published in the July/August 2020 issue of *Gas Processing & LNG*.

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Air Control Entech launches optical gas imaging drone

Remote inspection technology specialist Air Control Entech has developed a lightweight, optical gas imaging inspection system for use in global oil and gas inspection. Weighing less than 5,000 g, the unmanned aerial vehicle (UAV) is less than half the weight of other optical systems, allowing pinpoint visual accuracy of gas leak locations in challenging and previously inaccessible areas. It can also visually scan vast areas quickly.

The UAV's camera, with digital zoom capability and real-time data transfer, provides high-definition gas imaging to accurately detect leaks beyond the scope of normal human vision. Color-coding helps identify gases. The system can spot leaks from more than 100 m away and can be used in a variety of upstream, midstream and downstream environments, including refineries, process plants and decommissioning projects.

Novatek, Nuovo Pignone partner on CO_2 reduction

Novatek and Nuovo Pignone, part of Baker Hughes, signed a cooperation agreement aimed at reducing CO_2 emissions. According to the agreement, the companies intend to cooperate in developing electrical and gas turbine solutions for natural gas and LNG production, as well as solutions for reducing CO_2 emissions. The companies will also commence implementing a project to convert gas turbines to an H_2-based fuel gas mix. Baker Hughes is a main equipment supplier for Novatek's Yamal LNG and Arctic LNG 2 projects.

Baker Hughes debuts Onshore Composite Flexible Pipe

Baker Hughes recently launched its next-generation Onshore Composite Flexible Pipe to address the corrosion and cost-of-ownership challenges with conventional steel pipe for the energy, oil and gas, and industrial sectors.

The flexible, lightweight reinforced thermoplastic pipe (RTP) offers an economic and environmentally friendly alternative to resource-intensive onshore steel pipes, for optimizing the core structure of flowline and oil and gas pipeline networks. A key feature of the pipe is its spoolable design, making it easier, faster and 20% more cost-effective to transport and install vs. steel pipe.

The pipe offers an economic solution for the transport of CO_2 and H_2, as well as the conversion of existing infrastructure to carry gases. In addition, the pipe's non-corrosive materials can withstand contaminants without requiring chemical inhibitors, corrosion monitoring and inspection, or disruptive repair work, thereby reducing OPEX.

GAS PROCESSING & LNG

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